WORKING PAPER 83-4

THE IMPACTS OF CRUDE OIL SUPPLY CHANGES AND SUPPLY ALLOCATION

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MAY 1983

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Acknowledgements

We would like to thank several people who assisted in the preparation of this paper. Adele Crowley and Jeannette Palin handled the graphics work. Shirley Ingstrup and Cheryl DeWolf did a splendid job with manuscript preparation. These contributions were greatly appreciated.

We wish to thank the Institute's Executive Director, Dr. G. E. Angevine for his comments, and various individuals in the industry for assistance and suggestions. Of course, all errors and omissions remain our responsibility.

EXECUTIVE SUMMARY

This paper examines the petroleum supply and distribution effects of three forecast changes in previously anticipated 1990 oil supply. These changes are:

- the cancellation or delay of any additional oilsands projects;
- the cancellation or delay of a heavy crude oil upgrader in Alberta or Saskatchewan; and
- a sharp reduction in foreign crude supply in 1990.

A linear programming computer model (intended to allocate oil during shortages) developed by the Energy Supplies Allocation Board (ESAB) was used to allocate crude regionally for each case and to provide an indication of refiners' ability to adjust to these crude supply changes. Findings are summarized below:

- In every case surplus residual fuel oil was anticipated for 1990, emphasizing the ongoing need for refinery rationalization and conversion of heavy oil fractions.
- If no new oilsands plants proceeded, foreign oil imports would increase substantially. Due to quality differences, more low-quality foreign crude would be required by Quebec than the synthetic oil volume lost from the oilsands plants not being built. In addition, crude oil sulphur content would increase dramatically in Quebec indicating operating difficulties for refiners.
- The problem of shut-in heavy crude was compounded in the 'no upgrader' case as domestic refiners were unable to run all volumes available.
- In all cases, macroeconomic impacts would be significant;

- If, in an attempt to maximize efficient use of oil in Canada, governments did in fact allocate crude oil regionally using the ESAB model, radical adjustments in traditional crude supply patterns could occur. This is important for two reasons. First, such supply allocation could substantially hamper individual refiners' abilities to run their plants efficiently from month to month. Second, the model appears to exaggerate refinery yield flexibility and understate the impact of supply disruptions, therefore the effects of crude supply changes may be greater than described here.

Chapter 1

INTRODUCTION

1.1 Background

Since Canada is a net importer of crude oil, the risk of a serious disruption in foreign crude oil supply always exists. While the current depressed state of world oil demand tends to downplay this risk, Canada will nevertheless be vulnerable beyond 1990.[1]

Domestically, the world oil glut has contributed to the re-assessment of several major energy ventures. Cancellation of the Alsands mining project and the Cold Lake in-situ recovery project have had two effects. First, the volume of domestic crude oil available to Canadian refiners will be much less than previously anticipated. Second, lower quality domestic and foreign crude will fill this void, having implications for refined petroleum product (RPP) quality and yield. The delay of the Saskatchewan heavy oil upgrader will make the near term upgrading of lower quality domestic crude impossible, thus reducing the opportunity to deal with residual oil and sulphur problems in eastern markets. Further exacerbating these two problems is the withdrawal of partners from the Montreal heavy fuel oil upgrader, a plant that was to substantially reduce residual oil surplus in Quebec.

All of the preceding events, in conjunction with other factors, will affect the ability of Canadian refiners to efficiently meet domestic refined petroleum product demand. In this context, the term 'efficient' means meeting product demand with the lowest possible volume of oil feedstock and the lowest possible operating cost per cubic metre.

1.2 Objectives

The purpose of this paper is to examine the effects on refined petroleum product supply and distribution of three hypothetical changes in previously anticipated oil supply:

- the cancellation or delay of any additional oil-sands mining or in-situ recovery projects in Alberta beyond 1990;
- the cancellation or delay of a heavy crude oil upgrader in Alberta or Saskatchewan beyond 1990; and
- the sharp reduction of foreign crude oil supply in 1990.

The major emphasis will be to highlight some potential shifts in anticipated supply patterns, especially within the context of regional oil allocation by government, and to analyze some of the possible impacts of such changes. These impacts include:

- changes in crude oil allocation;
- refined petroleum product surpluses and shortages;
- changes in refinery utilization and operation on a regional basis; and
- shifts in foreign crude oil requirements.

1.3 Refining Efficiency

The efficient utilization of crude oil by Canadian refiners will continue to be a major issue over the next decade for three reasons.

First, a continued softness in world oil prices will not appreciably diminish the economic burden of oil imports, especially since future crude supply potential from conventional domestic sources will be dampened by lower oil prices. The volume of foreign crude imports could be reduced significantly, however, by increasing the efficiency of oil use.

Second, penetration of natural gas into eastern Canada will mean the displacement of distillate and residual fuel oil in residential and industrial markets. Lower refinery fuel oil yields (in favour of transportation fuels) would decrease the competition with natural gas in these markets.

Third, the problem of shut-in domestic heavy crude oil will continue. If conversion of the heavy end of the barrel were improved, it would enhance the marketability of domestic high density crude.

For these reasons, there will likely be considerable motivation to more closely match refinery yield to domestic refined product demand. This gain in refining efficiency can be accomplished using one or all of the following measures:

- refinery hardware modification;
- regulated demand manipulation;
- supply tailoring; and
- supply allocation.

These options are described in Table 1.1. To some degree, all four of these measures are in use today, but perhaps not entirely to the benefit of refiners. For example, regulated manipulation of demand by maintaining natural gas prices at 65 percent of crude prices should cause a load shift from distillate and heavy fuel oil to gas. The result has been the compounding of an already significant fuel oil surplus.

Some refinery hardware modifications are underway, but many have been delayed due to the recession, depressed world oil prices, and the high cost of capital. These expenditures will alleviate some of the evident supply imbalances but will not solve the entire problem. More refinery closures may also occur as surplus capacity forces less efficient plants out of the market.[2]

Supply tailoring has implicitly been occurring for years. On world markets, Canadian refiners have purchased those crudes that are best suited for their particular plants. Domestically, heavy and high sulphur crude remains shut-in as refiners attempt to maximize the purchase of light

TABLE 1.1

REFINED PETROLEUM PRODUCT (RPP) SUPPLY IMBALANCE CORRECTION

Method	Description	Example	Primary Responsibility
Refinery Hardware Modification	Installation of process units required to increase production of RPP in short supply or decrease production of RPP in surplus supply.	Additional reforming capacity to increase gasoline production, or hydrocracking to reduce residual fuel oil production.	Refiner
Regulatory Demand Manipulation	Rationing RPP in short supply or limiting use of competing fuels for products in surplus supply.	Gasoline rationing or a moratorium on new natural gas hookups to preserve oil markets.	Government
Supply Tailoring	Develop crude supply sources or purchase specific crude streams that have RPP yields closely matching demand.	The Saskatchewan heavy crude oil upgrader or selective purchase of specific foreign crudes.	Producer/ Refiner
Supply Allocation	Allocate existing crude types to specific refineries to minimize supply/demand balance in aggregate.	Allocating only light crudes and pentanes plus to hydro-skimming plants to minimize heavy fuel oil production.	Government

sweet crudes. Some aberrations exist, however. The purchase of heavy Mexican crude by the federal government was not an attractive supply option for refiners. In addition, the problems facing Saskatchewan's heavy crude oil upgrader means that technically superior synthetic oil may not become available to refiners for some time.

In some fashion, supply allocation is occurring now. In addition to the normal allocation of pipeline space by the National Energy Board (NEB) for eastern refiners, the Alberta government is actively allocating various crude types to a number of different purchasers. While this falls short of the omniscient, optimization type of crude allocation that could conceivably occur at the federal level during a supply crisis, it does illustrate the degree to which government has encroached on the supply activities of the refining industry.

1.4 Approach

On the premise that the efficiency of crude oil utilization will become even more important as the decade unfolds, it is difficult to escape the conclusion that some effort may be made to allocate crude supplies to individual refineries or regions. While such allocation measures may not be economically beneficial in aggregate, for this analysis it was assumed that an optimizing allocation process could be in place in 1990 for the following reasons:

- Both levels of government have already demonstrated certain forms of oil allocation; the Alberta government through the Alberta Petroleum Marketing Commission and the federal government through the Energy Supplies Allocation Board and the National Energy Board.

- Overall refining sector profitability could be maximized and foreign oil use minimized through a system of oil allocation, although the costs and mechanics of such a system are unclear.

- Inconsistencies resulting from arbitrary allocation of crude supplies cause analytical difficulties when the impacts of oil supply changes are examined.[3]

Based on a theoretically optimal computer allocation of crude oil to individual refiners in 1990, a base case and three impact cases are analysed by this paper. The three impact cases relate to: (1) no new oilsands supply before 1990; (2) no heavy oil upgrader before 1990; and (3) sharply reduced foreign crude supply in 1990. The analysis is concentrated primarily on the differences between the base case and impact case results rather than their absolute values. All four scenarios incorporated the same baseline refined petroleum product demand projection for 1990.

1.5 Organization

This paper consists of four parts. Chapter 2 reviews the general methodology of the analysis and describes the computer model utilized. Chapter 3 outlines the data employed for the base case and three impact cases. Chapter 4 is a summary of the model output, based on analysis detailed in Appendix B. Chapter 5 highlights major conclusions and recommendations for future work. The Appendices consist primarily of the detailed supply analysis and data tables.

Footnotes

[1]Current CERI forecasts of domestic supply and demand imply that Canada will be importing at least 7,500 m^3 per day in 1990. This is based on somewhat optimistic oilsands and frontier supply forecasts, so the true import level could be substantially higher.

[2]The analysis was completed before recent announcements of plant shutdowns include BP and Imperial in Montreal, Shell in Oakville and St. Boniface, Gulf in Kamloops, and capacity cuts by Gulf at Montreal East and Clarkson.

[3]The arbitrary allocation of crude oil can significantly influence study results due to the critical nature of oil supply to each refining region. Therefore, if an optimizing type of approach is used, consistency should be increased.

Chapter 2

MODEL DESCRIPTION AND METHODOLOGY

2.1 Model Selection

Table 2.1 summarizes the selection criteria employed in choosing the most attractive modelling option for this analysis. A yield-modelling approach such as that of the Energy Supplies Allocation Board (ESAB) model was selected for four reasons.

First, the model is designed to allocate crude oil on a regional or plant-specific basis. This was considered a definite advantage because it avoids the problem of arbitrary oil allocation. In addition, the model would probably be the vehicle for any oil allocation program implemented, thus fitting well with the concerns expressed in Section 1.4.[1]

A second reason is that the ESAB model is based on empirical yield data. Other modelling approaches do not have access to this confidential data, using instead technical estimates of actual operating conditions with adjustments to theoretical values.

The third reason is that the ESAB model is refinery-specific. A linear programming approach that simulates specific process units is usually adopted on a regional basis, introducing margins for error attributable to the aggregate nature of the model.

Fourth, even though the ESAB model will form an integral part of any oil allocation scheme, it has rarely been tested or evaluated by an independent organization.

Analytical weaknesses of the model are discussed in Section 2.4.

TABLE 2.1

REFINING MODEL SELECTION CRITERIA[a]

Selection Criteria	Alternatives	
	Yield Modelling[b]	Process Modelling[c]
Allocation Ability	Good	Fair
Flexibility	Fair	Good
Cost Effectiveness	Good	Poor
Empirical Yield Detail	Good	Fair
Refinery Infrastructure Modification	Poor	Good
Documentation	Poor	Fair
Disaggregation by Plant	Good	Poor
Overall	Good	Fair

[a]These selection criteria are based on the theoretical strength and weakness of a given modelling approach, not necessarily as related to a specific model.

[b]Similar to the Energy Supplies Allocation Board model where empirical yields are known.

[c]A theoretical construction which is ultimately fine tuned to reflect real world conditions.

2.2 Purpose

The ESAB model was conceived in response to the Arab oil embargo of 1973/74 and developed subsequently to the creation of the Energy Supplies Allocation Board. The purpose of the model is to ensure that shortages of refined petroleum products are minimized during an oil supply crisis. In theory, the model would reduce overall hardship by allocating crude oil to refiners in an optimal fashion.[2]

2.3 Solution Method

The ESAB model is a linear programming (LP) formulation of the Canadian refining industry. The major refineries in all regions are explicitly represented. The Board has the power to request confidential yield data from every refinery in Canada. This yield information is incorporated in the model to show the actual flexibility the refiner possesses for each crude type by reporting yields under max-gasoline and max-distillate operations.

This solution method eliminates the need for complex simulation of specific refining process units. These yields represent actual refinery performance, and therefore already embody variances in actual versus theoretical plant performance.

For the analysis in this paper, refined petroluem product demand was specified on a regional basis. Crude oil supply was specified on a national basis, with all transportation constraints fully reflected in the solution methodology. Both supply and demand vectors were exogenous.

The model's objective function is to minimize refined petroleum product shortages. Constraints include:

- maximum available oil supply by stream;
- physical crude oil refining capacity;
- maximum and minimum refined product production; and
- standard non-negativity constraints.

The model results could only be assessed on a regional basis, given the confidentiality requirements of the ESAB. Five regions and ten refined products are addressed in the model, as summarized in Table 2.2.

TABLE 2.2

ESAB MODEL DISAGGREGATION

Regions	Refined Products
British Columbia Prairies[a] Ontario Quebec Altantic[b]	Petrochemical feedstock Motor gasoline and aviation gasoline Aviation fuel - Kerosene type (Jet A) Aviation fuel - Naphtha type (Jet B) Stove oil and kerosene Diesel Light fuel oil Heavy fuel oil Asphalt Lubricating oil and grease

[a]Includes the provinces of Manitoba, Saskatchewan, and Alberta, and the Northwest Territories.

[b]Includes the provinces of New Brunswick, Nova Scotia, Prince Edward Island and Newfoundland.

In the model, crude oil supply is specified by source. Every major domestic and foreign crude stream is represented. Light domestic oil to eastern markets is usually specified as an Interprovincial Pipeline (IPL) mixed stream.

2.4 Analytical Weaknesses

The modelling approach selected has some important weaknesses. First, the model does not have the ability to incorporate changes in refinery configuration anticipated for 1990. While this would be a major problem if absolute supply and demand numbers were being analyzed, the emphasis in our analysis was more on relative changes from a similarly derived base case. In this relative sense, directional supply and demand changes should be adequately reflected.

Second, the recent downturn in refined petroleum product demand could mean that the exogenous 1990 demand vectors may be somewhat high. This could exaggerate absolute product shortages but again, in relative terms, the direction of change should be adequately represented. In addition, the economic downturn has also affected supply, and the net result may be insignificant.

A third problem relates more to the ESAB model itself than the general modelling approach. After detailed examination of model output, it was found that the model may overstate refinery yield flexibility. The impacts of supply disruptions could therefore be underestimated. This problem is discussed in Chapter 4.

Finally, refiners have expressed concern that the model does not adequately represent real-life operating constraints of specific plants. Such factors could be built into the model, but would significantly increase the complexity of the solution, cost of running, and the potential for errors occurring due to the detailed nature of the model.

Footnotes

[1]For a discussion of another method to overcome the allocation problem see Douglas J. Haughey, "Crude Oil Supply and Demand: Major Issues and Alternate Scenarios," (Calgary: Canadian Energy Research Institute, July 1981), Working Paper 81-1.

[2]Pursuant to Section 12 of the Energy Supplies Emergency Act (1979), the Energy Supplies Allocation Board (ESAB) developed a mandatory allocation program for crude oil and refined petroleum products, of which the ESAB computer model is an integral part.

Chapter 3

INPUT DATA FORMULATION

3.1 Scenario Selection

The year 1990 was chosen as the reference year for the analysis for several reasons. First, 1990 is far enough in the future that energy megaprojects planned today would have been at or near completion. Therefore, the full impact of delays in such projects could be assessed. Second, year 1990 is near enough that conventional forecasting techniques can provide estimates of reasonable value. Third, 1990 is a benchmark year for energy forecasting and analysis, as well as an ambitious target for self-sufficiency.

A base case refined petroleum product demand forecast was developed for 1990. This forecast was paired with four supply cases to create the four supply/demand scenarios analyzed in this paper. They are summarized in Table 3.1.

The 'no new oilsands' case (NOS) was selected in response to the recent demise of the Alsands and Cold Lake projects. The potential refining implications related to the loss of these large synthetic crude oil volumes are an issue of major importance because this foregone domestic production will be replaced by lower quality foreign oil.

The 'no heavy crude oil upgrader' case (NUG) also was considered important for three technical reasons that inhibit heavy oil's marketability:

- heavy crude oil is difficult and expensive to produce and transport;
- heavy crude oil is more expensive to refine due to high sulphur and metals content; and
- heavy crude oil has a low yield of light products.

TABLE 3.1

SELECTED CRUDE SUPPLY/DEMAND SCENARIOS[a]

Scenario	Abbreviation	Year	Description	
			Supply	Demand
Base case	BAS	1990	Base case	Base case
No new oilsands	NOS	1990	Base case supply less incremental upgrader production	Base case
No heavy crude upgrader	NUG	1990	Base case supply less upgrader production plus equivalent heavy oil supply	Base case
Reduced foreign crude oil availablity	RFC	1990	Base case supply less almost all foreign crude oil	Base case

[a]See appendix A.1 and A.2 for detailed supply and demand figures.

While no loss of domestic production would occur, the marketability of heavy Lloydminster type crude would fall substantially, especially if supplies of pentanes-plus for diluent were not available.

The 'reduced foreign crude oil' case (RFC) examines the impacts of a major foreign oil supply disruption. It is based on the premise that Canada will not be self-sufficient by 1990, making the risk of supply disruption a serious consideration, the current state of the world oil industry notwithstanding.

3.2 Demand Estimates

Compared to 1980, the 1990 forecast of refined petroleum product demand showed reductions in oil demand for Quebec and Ontario. Overall demand in the west was shown to rise. In total, Canadian crude oil demand was forecast to fall noticeably from 1980 levels. This forecast is presented in detail in Appendix A.2.

Recent indications are that these demand estimates may be overstated. The direction of the projected trends are however, correct.

3.3 Supply Estimates

The differences between the base case and the NOS, NUG and RFC cases are summarized in Table 3.2. For the NOS case, synthetic crude oil production is 46 000 m^3 per day less than the base case. This represents the equivalent of Alsands and Cold Lake, plus a Syncrude expansion or several small scale pilot plants that do not go ahead. Notice that foreign crude oil supplies were increased by a similar amount to replace the decreased domestic supply.

For the NUG case, synthetic crude availability is assumed to fall 7 000 m^3 per day, or the equivalent of a 50 000 barrel per day plant. Lloydminster blend then rises by a nearly equivalent amount as feedstock previously committed to the upgrader must then be marketed to refiners.

TABLE 3.2

DIFFERENCES FROM BASE CASE SUPPLY,[a] 1990
($10^3 m^3/d$)

Crude Source	SUPPLY CASE		
	No New Oilsands Case (NOS)	No Heavy Crude Oil Upgrader Case (NUG)	Reduced Foreign Crude Oil Supply (RFC)
Synthetic Crude	-46.0	-7.0	0
Lloydminster Blend	0	+8.0	0
Foreign Crude[b]	+48.0	-1.0	-46.0

[a]See Appendix A for details.

[b]These are approximate adjustments to foreign crude supply since technically the model is not constrained by foreign oil supply for these cases.

It should be noted that in all cases, foreign crude availability for Canada in 1990 is assumed to be 50 percent Saudi Arabian Light, 20 percent Tia Juana Light (Venezuela), 20 percent Bachequero (Venezuela), and 10 percent Isthmus (Mexico).

Chapter 4

ANALYSIS OF RESULTS

The purpose of this chapter is to summarize the results and discuss the important findings of the model simulations. Throughout this chapter the three cases (NOS, NUG, and RFS) are analysed in terms of deviations from the base case. A detailed description of model results appears in Appendix B.

4.1 No New Oilsands (NOS)

The no new oilsands case examined the impacts of no additional oilsands plants being completed by 1990 in Alberta. This represents a reduction of about 45 000 m^3/d of synthetic crude oil from the base case.

4.1.1 Crude Oil Supply Shifts

As illustrated in Figure 4.1, Quebec would lose 35 000 m^3/d of synthetic oil (vis-a-vis the base case) if no new oilsands plants were built. Quebec refiners would be forced to import 47 000 m^3/d of poorer quality foreign crude to equal the light refined product produced from only 35 000 m^3/d of synthetic crude oil.[1] This 12 000 m^3/d import boost would mean increased risk of supply disruption for Quebec refiners.

Figure 4.2 illustrates the regional shifts in crude supply that accompany the NOS case. The major changes were in Ontario, Quebec and the Prairies. The quantity of mid-density crude allocated to Quebec increased dramatically due to the large increase in foreign oil usage. Quantities of light crudes fell as they were shifted away to other regions by the model to optimize nationwide allocation of light feedstocks. There would be a large increase in Quebec fuel oil production.

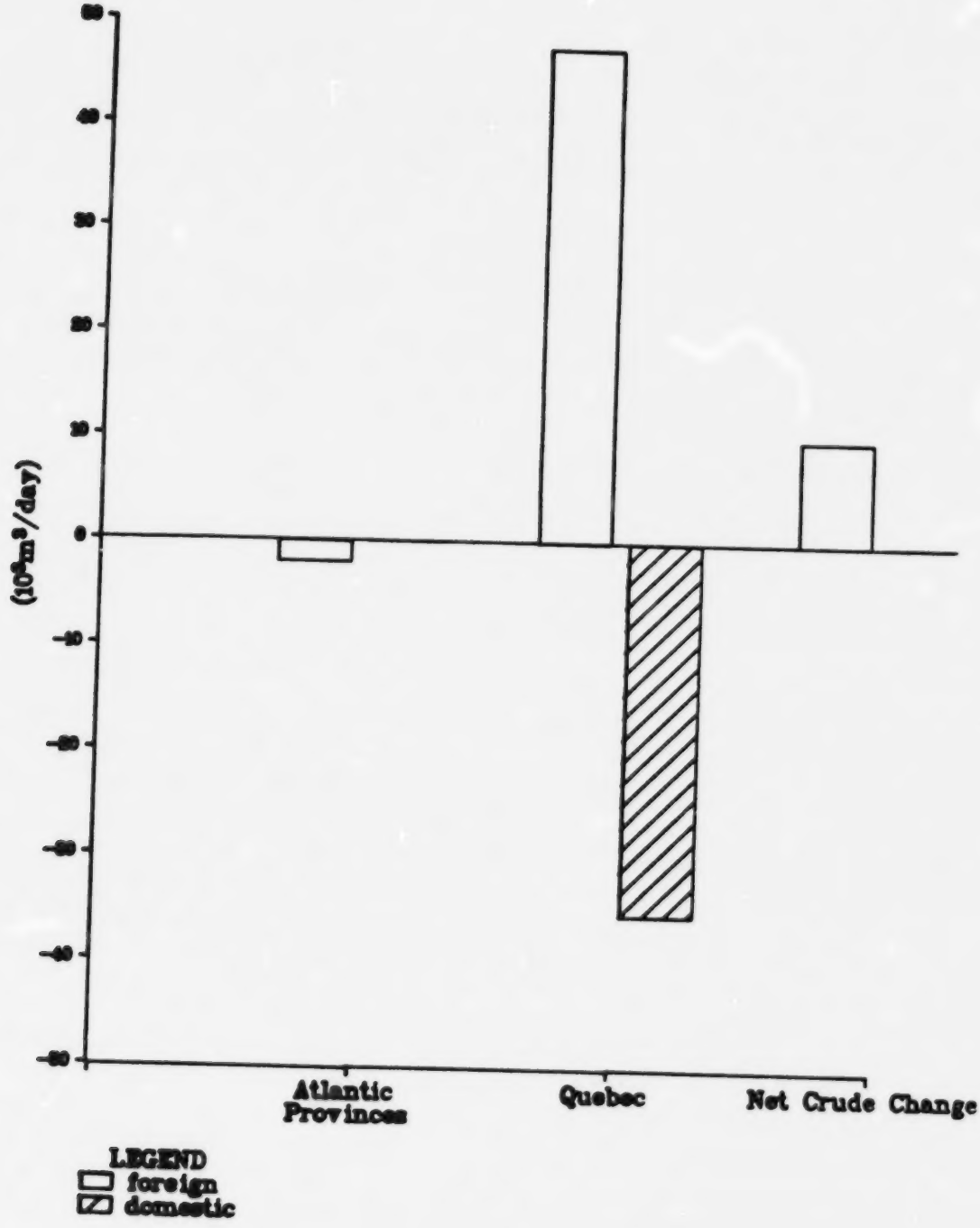

Figure 4.1: Foreign Crude Supplied Relative to Base Case: No Oilsands Case

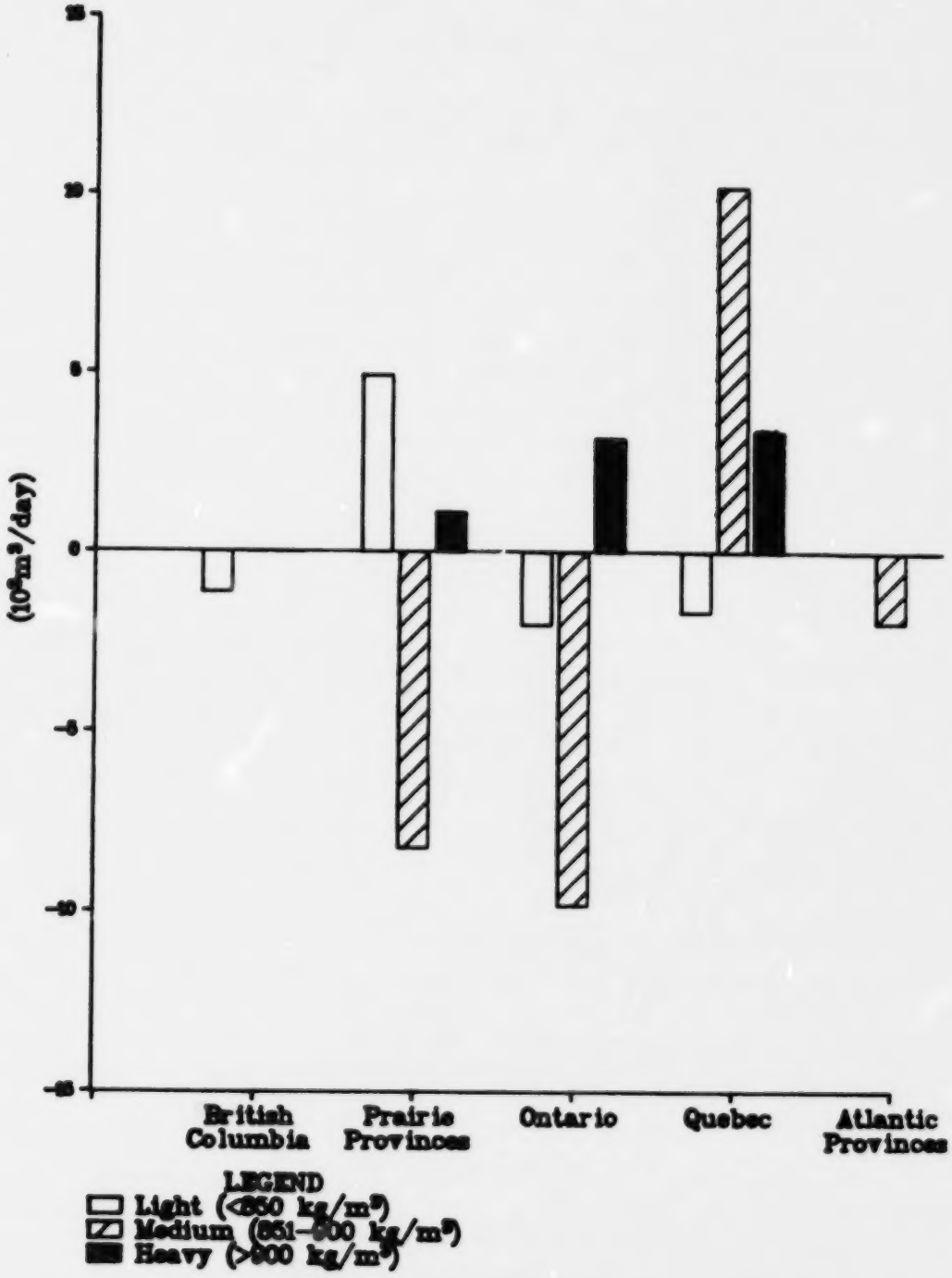

Figure 4.2: Crude Supply Changes From Base Case: No Oilsands Case

While crude quality seemed to fall in Ontario, there were significant increases in pentanes and other high quality streams. The result was a reduction in total Ontario oil requirements due to these specific shifts to preferred crudes. This reduction means that Ontario refiners may be able to operate more efficiently due to the changed crude mix allocated by the model.

4.1.2 Refined Product Production Shifts

In every region a surplus of fuel oil existed (furnace plus heavy fuel oil).[2] As illustrated in Figure 4.3, however, only Ontario and Quebec showed significant shifts from the base case. The reduction in the Ontario fuel oil surplus was due mostly to the changes in crude supply allocated to that region as described in the previous section.

Quebec fuel oil production rose dramatically above the base case levels. This was due primarily to the loss of synthetic oil and its replacement by lower quality foreign crudes. The effect was that, in order to meet light products demand, Quebec refiners would have to increase crude runs, thereby compounding the existing fuel oil surplus. The effect would be even stiffer competition with gas for industrial markets in Quebec, and likely increases in residual fuel oil exports.

4.1.3 Refinery Impacts

While average crude oil sulphur levels increased for all regions in the NOS case versus the base case, the increase in Quebec was dramatic. This is undoubtedly due to the loss of synthetic supply (which has an extremely low sulphur content), and its replacement with higher sulphur imports.

The potential burden of these high sulphur levels on Quebec refiners is uncertain. It is not clear whether the computer model allocates cutback from the refineries' distillate pool in order to lower sulphur levels in residual oil inventories. If the model does not, this implies that the heavy fuel oil production would be excessively high in sulphur and therefore very difficult to market.[3]

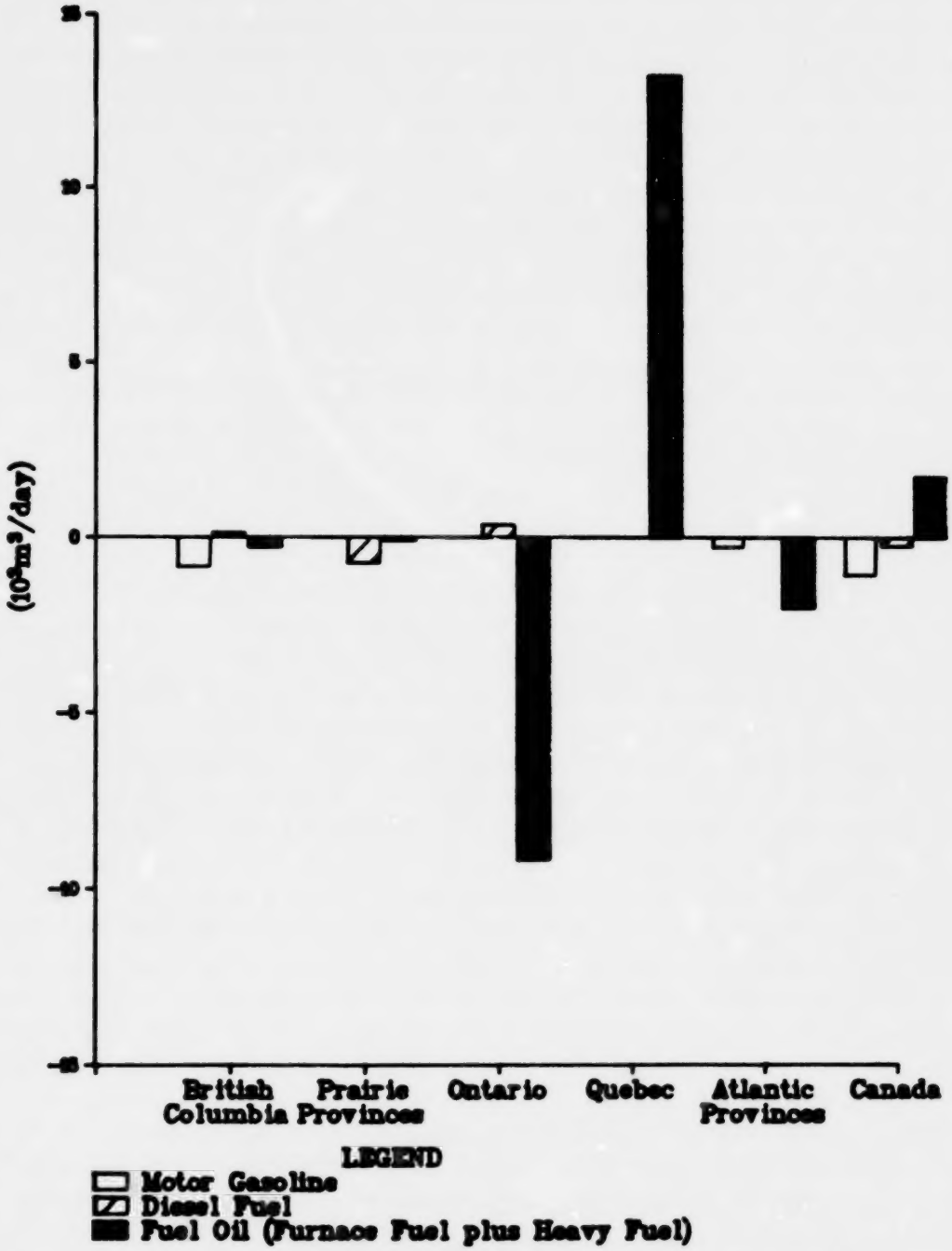

Figure 4.3: Refined Petroleum Product Production Shifts Relative To Base Case: No Oilsands Case

The large fuel oil production jump in Quebec between the base case and the no new oilsands case brings the Quebec heavy fuel oil upgrading question to the forefront. If failure to proceed with further oilsands development does add to the Quebec problem, it appears that such a scenario would merit renewed examination of the Montreal central heavy fuel oil upgrader, or individual refinery upgrading projects. About 480 000 m^3 per day of vacuum resid conversion capacity will be required worldwide by the year 2000.[4] It should also be noted that no new oilsands projects could be a major blow to the small number of refiners who have tailored part, or all, of their plant to a synthetic crude oil feedstock. While the confidential nature of these refinery-specific impacts makes them difficult to quantify, expensive capital expenditures to refit existing process units would almost certainly be required.

4.1.4 Economic Impacts

The demise of the synthetic oil projects could mean an additional 45 000 m^3/d of crude oil imports by 1990. At current prices, this implies a flow of $4.5 billion per year to foreign producers for crude that could be produced domestically. This additional import dependence would increase the risk of foreign supply disruption that Canada could face.

Another economic impact of the NOS case is the foregone income and employment benefits related to construction and operation of a 22 000 m^3/day synthetic crude oil plant. It has been estimated that 592,000 man-years of employment would be foregone and $54 billion of income lost, with a large portion of these lost benefits accruing in Ontario and Quebec.[5]

A third effect of the NOS case relates to pipelines. Throughput on the Interprovincial Pipeline System would fall, and if oil were allocated as specified by the model, the Sarnia-Montreal leg would be shut down. Correspondingly, transportation tariffs would rise in response to the lower throughput over which fixed costs must be spread. On the other hand, Portland Pipe Line throughput would increase substantially to handle increased imports to Montreal. In

the latter case, pipeline or port capacity could become a limiting factor.

4.2 No Heavy Crude Oil Upgrader (NUG)

This section describes the implications of a delay in putting a Saskatchewan heavy crude oil upgrader in place beyond 1990. It is assumed that the upgrader would process about 7 000 m^3/d of heavy crude, converting it to a light synthetic oil. With no upgrader, this quantity of heavy oil could only be marketed to those domestic or foreign refiners able to run it.

4.2.1 Crude Oil Supply Shifts

Figure 4.4 describes the changes in foreign crude supply relative to the base case. Total foreign crude imports are virtually unchanged under the NUG scenario. The slight decrease is insignificant and likely due in part to a reallocation of specific foreign crudes between Quebec and the Atlantic region. Total domestic crude supplies for Quebec increased substantially resulting in a large net increase of crude run by Quebec refiners.

Figure 4.5 shows the shifts in crude types supplied to each region, relative to the base case. Quebec and Ontario bear the brunt of the increased heavy crude oil supply.

The additional Lloydminster Blend was almost completely allocated to Ontario by the model. To compensate for this increased heavy feedstock, an additional volume of synthetic crude was reallocated from Quebec to Ontario, resulting in a net decrease of 15 000 m^3/d of synthetic crude to Quebec refiners.

Light conventional crude was reallocated from Ontario to Quebec to compensate for Quebec's loss of synthetic crude. The net effect was an increase of total crude runs by Quebec refiners. The incremental feedstock is primarily light domestic crude along with a small increase in heavy oil. It is significant to note that in both NOS and NUG cases, crude runs in Quebec increase substantially. This implies that, given identical demand, the crude slate allocated to Quebec

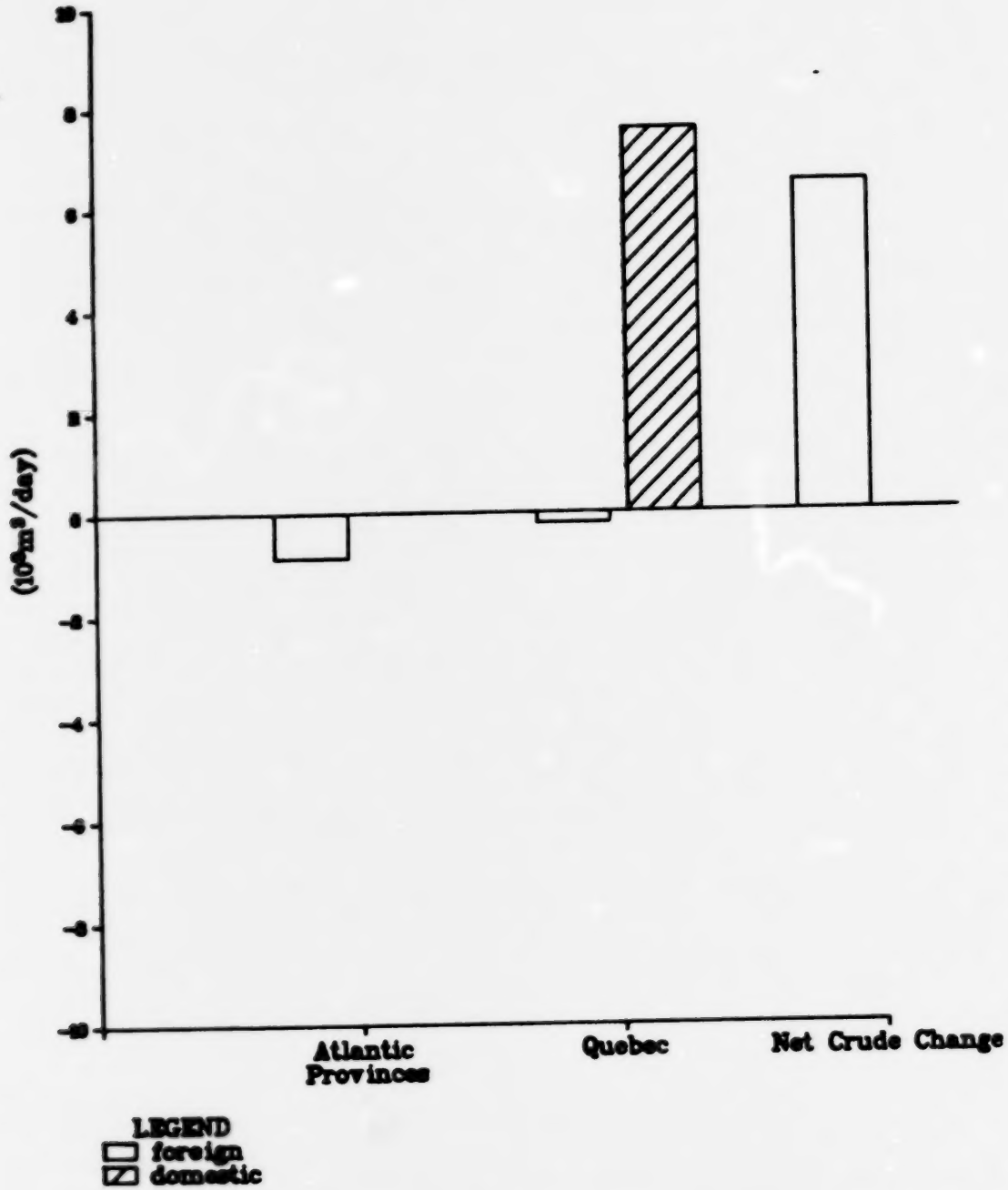

Figure 4.4: Foreign Crude Supplied Relative to Base Case: No Heavy Oil Upgrader Case

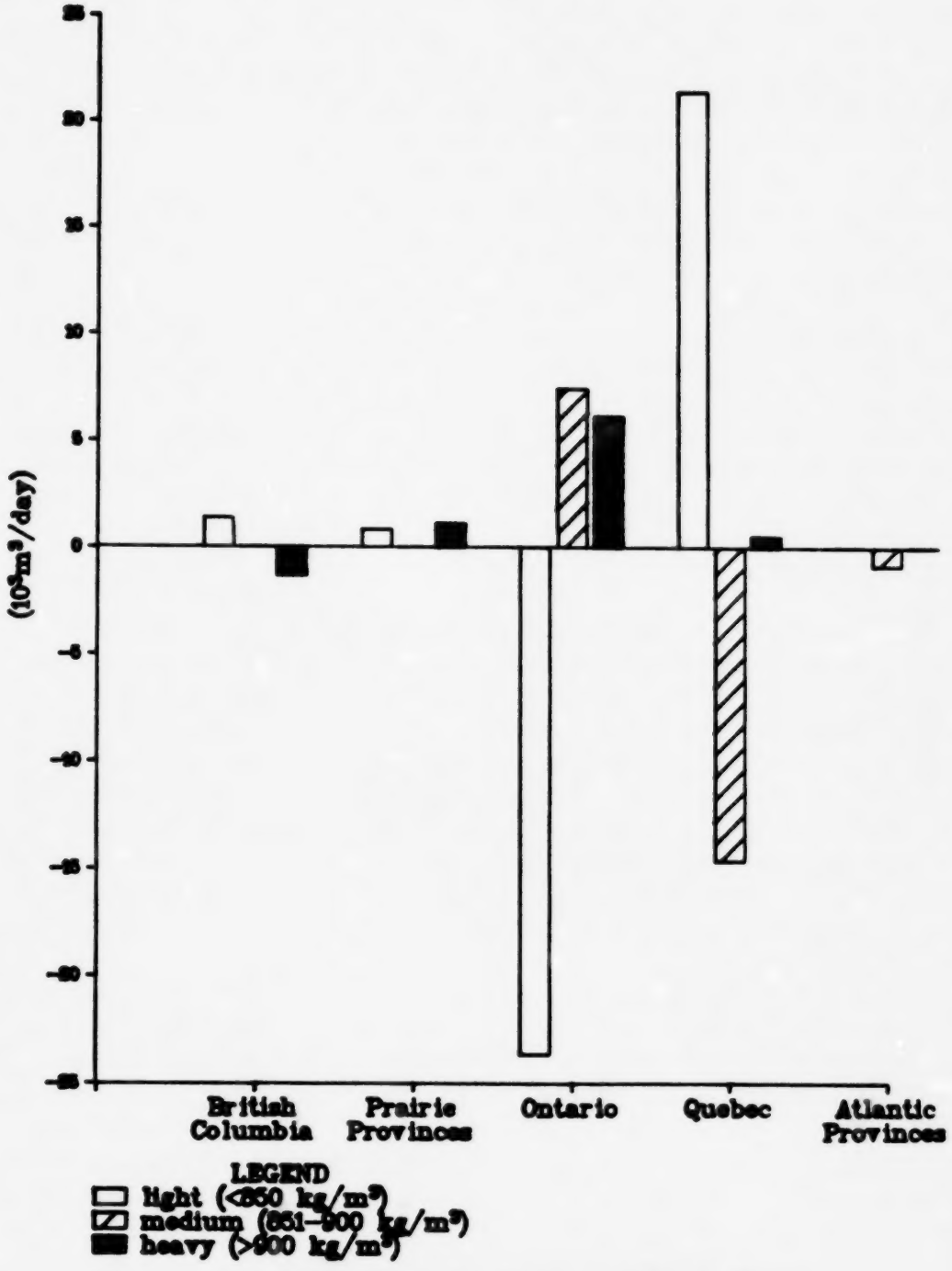

Figure 4.5: Crude Supply Changes From Base Case: No Heavy Oil Upgrader Case

must be poorer than the base case, and could cause major hardships for refiners.

Figure 4.5 shows that crude supplies allocated to Quebec in the NUG case shifted toward lower density oil types. Overall, however, it appears that the most substantial reduction in medium grades was for synthetic crude. Therefore, the refiners' problems with heavy fractions and sulphur were probably compounded, even though the weighted average density decreased.

4.2.2 Refined Petroleum Product Production Shifts

Canadian production of all refined products was slightly reduced relative to the base case. All five regions maintained their excess production of fuel oil (distillate plus residual). The only significant shifts were in Quebec and Ontario, as described in Figure 4.6.

Quebec had a moderate increase in fuel oil production due to the reduced quality of crude supplies discussed in section 4.2.1. However, the impact on traditional Quebec fuel oil markets should not be that pronounced. Ontario, however, experienced a sharp decrease in fuel oil production. This is partially explained by the additional quantities of synthetic oil allocated by the model to Ontario. The effect on fuel oil markets could be substantial. Interregional product transfers and cross border fuel oil movements, however, would mitigate these impacts.

4.2.3 Refinery Impacts

In the base case, certain Ontario refineries could be experiencing physical bottlenecks in upgrading conversion units such as catalytic crackers, hydrocrackers, or cokers. This could result in heavy fractions bypassing these units, going directly to the fuel oil pool and requiring light end cutback as a diluent.

In the NUG case, Ontario refineries received increased quantities of synthetic crude. Bottlenecks in their conversion units may have been relaxed, allowing increased

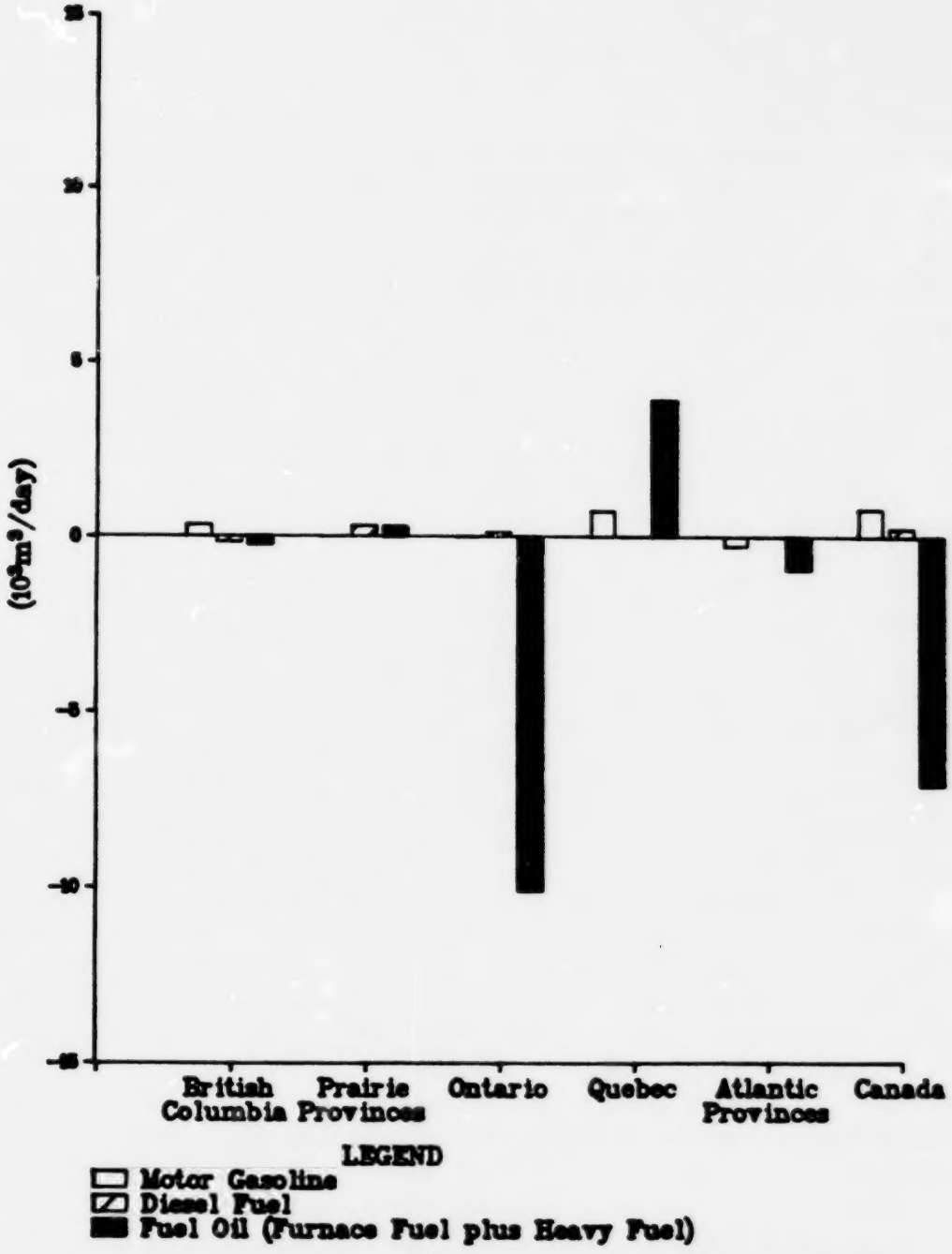

Figure 4.6: Refined Petroleum Product Production Shifts Relative To Base Case: No Heavy Oil Upgrader Case

capacity for heavy crude. The net effect of the NUG case may be a more efficient utilization of downstream conversion capacity, thus partly explaining a sharply reduced fuel oil production surplus to requirements.

In addition, sulphur and metals content can be a problem to refiners. Sulphur levels of marketed fuel oil are controlled by quality standards and high metals content of crude can poison cracking unit catalyst. Therefore, it is feasible that synthetic crude with very low sulphur and metals content could free up cracking or hydrotreating capacity for the additional heavy crude oil allocated by the model.

While the sharp reduction in fuel oil production can partly be explained by some of these factors, it may simply be a manifestation of the model's overstatement of yield flexibility. Actual yields may not be able to match these theoretical values.

4.2.4 Economic Impacts

If a heavy crude oil upgrader does not proceed, the foregone jobs and investment in Canada would be substantial. Apart from these multiplier effects, there would also be an adverse effect on heavy crude oil producers in Alberta and Saskatchewan.

The most immediate difficulty will be shut-in capacity. Heavy oil producers face a serious marketing problem. The upgrader would provide a ready market for surplus capacity. Without the upgrader, however, only two markets would exist. Eastern refiners claim they are technically limited in the amount of heavy oil they can take. United States refiners are facing demand constraints, and this market is tightly regulated by National Energy Board price and volume controls.

In the longer term, heavy oil exploration and development would fall below base case levels if the upgrader were not put in place. Domestic resource potential would not be fully exploited, and increased foreign imports could be required to replace this foregone supply. The overall effect

would be lower activity in the resource sector, potential technical problems for refiners, and increased reliance on expensive foreign crude oil.

One solution to the problems faced by a major central upgrader may be smaller 1 500-2 500 m^3/d expandable plants. Such upgraders would use a hydrocracking/hydrotreating or coking/hydrotreating process, requiring shorter construction lead times. It has been argued that the smaller upgrader can be just as cost-efficient as the larger version, with lower capital cost being a major advantage.[6] Such claims have not been conclusively proven.

4.3 Reduced Foreign Crude Supply (RFC)

The reduced foreign crude supply case examined the 1990 impacts of a very sharp reduction in foreign crude availability. This represented about a 46 000 m^3/d reduction from the base case.

4.3.1 Crude Oil Supply Shifts

The total foreign crude oil supply reduction was 16 percent of base case supply. The model reduced regional crude supply as follows:

Region	Percent Reduction from Base Case Crude Supply
British Columbia	29%
Prairies	11%
Ontario	17%
Quebec	11%
Atlantic	23%
Weighted Average	16%

While only Quebec and the Atlantic region use foreign crude, the model spread the shortfall throughout the country by reallocating domestic crude supplies. In every region the reduction was significant, and would likely make it very difficult for refiners to meet refined petroleum product demands.

The model allocated about 70 percent of the available foreign crude to the Atlantic region, with the remaining 30 percent being dedicated to Quebec. This was not surprising, given the Atlantic region's very limited access to domestic crude.

The shifts in regional crude supply patterns for the RFC case are depicted in Figure 4.7. The major shifts from the base case occurred in the Atlantic, Quebec and Ontario regions.

The sharp reduction in mid-density supply to the Atlantic region was directly due to the loss of foreign crude. This was offset in part by volumes of domestic crude moved to the Atlantic region by tanker. Such inter-regional transfers could be achieved in three ways. The first (and probably least attractive) is shipment of Alberta crude via TransMountain Pipeline to an export point on the West Coast. The crude would be loaded on Panamax-type tankers and shipped via the Panama Canal to Atlantic refiners. While possible, this method is very expensive, time consuming, difficult to manage, relies heavily on a transportation system not completely within Canada, and forces Atlantic refiners to run unfamiliar crude types.

The second method would be to ship whatever additional crude volumes possible via Interprovincial Pipeline to Montreal, where it would be moved along the St. Lawrence river to Atlantic refineries. While this method has seen limited use in alleviating shut-in domestic oil problems in western Canada, both it and the first methods are very costly and would only be implemented on a major scale during times of dire need.

The third method is simply an extension of offshore exchanges already in use. Alberta and B.C. crude could be moved to U.S. refiners in exchange for imported crude, destined for the U.S., being diverted to Atlantic refiners. This would rely in large part on the efficient and flexible supply systems of multinational oil companies.

In Quebec, the major increase in low-density crude supply resulted from an eastward shift in light feedstocks,

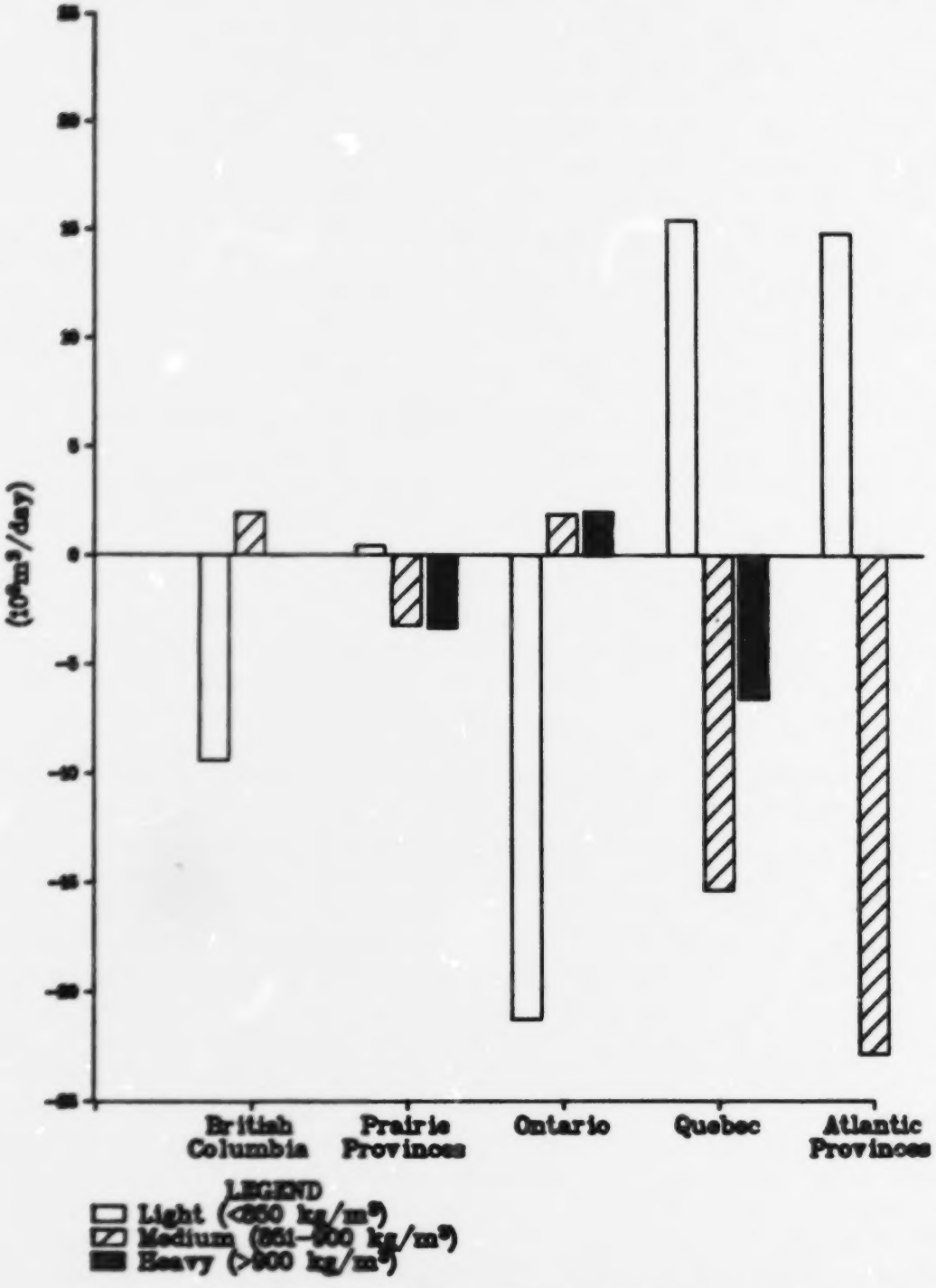

Figure 4.7: Crude Supply Changes From Base Case: Reduced Foreign Crude Case

primarily light streams normally destined for Ontario. The reduction in mid-density oil was a consequence of the lower foreign oil availability.

Both Ontario and British Columbia were allocated lower volumes of light oil vis-a-vis the base case. These light crudes end up in the Quebec and Atlantic regions. Condensate supply to British Columbia was reduced and traditional streams such as Peace River and Federated were reduced significantly. This could mean difficulties for Lower Mainland refiners with, historically, fairly stable crude diets.

4.3.2 Refined Product Production Shifts

The model results describing production of refined petroleum products are extremely difficult to rationalize for the reduced foreign crude supply case. While the crude allocation discussed in section 4.1 clearly shows a significant reduction in crude supply of at least 10 percent in all regions for the RFC case, all light and middle distillate production was virtually unchanged from the base case. Intuitively this is very difficult to reconcile. There are, however, two potential explanations.

First, it is possible that the model's crude oil allocation for the RFC case was so effective that efficiency of crude oil use was increased tremendously for Canada. It is true that there were substantial re-allocations of crude in the RFC case as compared to the base case. It is very unlikely, however, that these re-allocations alone could maintain required refined petroleum product yield in the face of a 16 percent feedstock reduction.

The second possible explanation is related to the refinery data endogenous to the model. In many cases, the technical detail may not be sufficient to accurately reflect real life technical and economic operating conditions faced by refiners. Therefore, it is possible that regional refinery flexibility has been over-estimated by the model. Consequently, when crude supply disruptions occur, the degree to which refiners can alter plant operation to compensate for these changes is overstated by the model.

Overall, it appears that the re-allocation of domestic oil during a foreign supply disruption may help soften the blow. It is not clear, however, that the effects could be totally mitigated by the refinery flexibility presumed, especially if technical and economic factors are considered.

4.3.3 Refinery Impacts

The radical alteration of crude allocation patterns during a foreign oil supply disruption would have three major impacts on the refining sector. First, a shift in historical feedstock supply could mean operating problems that may prove difficult to resolve. Unfamiliarity with feedstock can cause less than optimal plant operation and a potentially costly learning curve.

Second, the product yields required from the allocated feedstock may be technically or economically impossible to achieve given the actual operating characteristics of the plant. For example, a heavier crude supply may require running a refinery hydrocracker at rates that simply cannot be achieved.

Third, changed supply and demand patterns could cause major dislocations of feedstock and refined product transportation. Pipeline and/or port capacity scheduling problems could occur if large volumes of Atlantic-destined crude were shipped via Interprovincial Pipeline to Montreal port facilities. In addition, shifts in refinery yield patterns after a crude supply disruption, coupled with possible rationing of refined petroleum products, could substantially shift the traditional rail and truck movement of refined products. It is likely that more costly long hauls would occur if established markets are curtailed or product deficiencies occur in regions normally supplied by other refining centres.

4.3.4 Economic Impacts

The impacts of a disruption in foreign crude supply would depend in large part on the duration and severity of the shortfall. If it is assumed that the deficiency was greater than the 7 percent required to trigger supply allocation procedures and that the crisis was prolonged enough to

cause ongoing hardship, several economic impacts could be felt.[7]

The cost of refined petroleum products would rise for three reasons. First, throughput in all regions would be lower, therefore refinery operating cost per cubic metre would increase as fixed costs are spread over a smaller volume. Second, the supply and demand dislocations caused by government allocation would increase transportation costs for crude oil and refined petroleum products. Third, government tampering with traditional crude supplies would cause refining cost increases as refiners are forced to operate their plant to meet product demands at any cost, rather than operating to produce cost competitive products.

Unemployment could rise in certain industries that are low on the priority list for refined product rationing.[8] Such industries could include energy intensive consumer product sectors or some commercial transportation enterprises. These employment effects would also be felt in areas highly sensitive to increases in energy prices.

Inflation would increase in response to refined product price increases accompanying a supply shortage. This effect may, however, be offset by the deflationary effect of reduced commercial and industrial activity. Overall economic growth rates would almost certainly be reduced.

Footnotes

[1]This 12 000 m^3/d import increase would be offset by import reductions in other regions (primarily Ontario).

[2]The three major refined petroleum product supply balances examined were gasoline, diesel, and fuel oil (furnace and heavy combined).

[3]Environmental legislation will probably have a major effect on high sulphur residual fuel oil sales for industrial boiler use. Heavy price discounting is a definite possibility.

[4]Fritz and Gray, "Resid Conversion Through 2000," The Journal of Energy and Development.

[5]Gordon W. Douglas and James A. MacMillan, Interregional Economic Impacts of the Alberta Alsands Project. (Calgary: Canadian Energy Research Institute, September 1982), Client Research Report 82-2.

[6]RTM Engineering Ltd., Proposed Small Upgrader Program, September 1982.

[7]The 7 percent figure is the shortage threshold after which the International Energy Agency will start allocation procedures among OECD countries.

[8]Such low priority industries include recreational establishments, service stations, hotels and government operations, and other service industries.

Chapter 5

CONCLUDING COMMENTS

5.1 Conclusions

The major impacts of the NOS, NUG, and RFC cases addressed in this paper are summarized in Table 5.1. Several conclusions are warranted.

The impacts of delayed oilsands development would seem to be substantial. In addition to the economic boost that would be missed, significant refining problems would occur as low quality foreign oil replaced foregone domestic synthetic supply. Residual fuel oil surpluses would increase regionally.

The positive economic effects postponed by a delayed construction of a heavy crude oil upgrader would be less than in the oilsands case, but nonetheless similar in nature. The problem of shut-in heavy crude would continue, along with the ever-present transporation problems. It is expected that the major refining impacts would stem not so much from foregone upgraded oil supply, but rather from the availability and use of the heavy, high sulphur crudes.

A major loss of foreign oil supply would mean radical changes in domestic crude supply patterns and refining costs. Western Canadian crude could move to the Atlantic region at a very high cost, and all refiners would be hardpressed to meet refined petroleum product demands. It is unlikely that refiners could adjust quickly to a supply disruption. Any rationing or allocation scheme would, in addition, be costly and burdensome to administer.

An important final point relates to the computer model used. Throughout the analysis, problems were encountered with the yield flexibility impact in the model for each refining region. The model's yield coefficients are likely accurate, so the problem may lie with the complex technical

TABLE 5.1

IMPACTS OF CRUDE SUPPLY CHANGES

Impact	DEGREE OF IMPACT — SCENARIO		
	No New Oilsands (NOS)	No Heavy Crude Oil Upgrader (NUG)	Reduced Foreign Crude Supply (RFC)
Crude Oil Allocation	fairly major regional changes	limited regional reallocation	major reallocation of regional supply
Crude Oil Transportation	Portland P/L capacity question	diluent problems	large increase in in non-pipeline, Sarnia - Montreal capacity constraint
Refinery Flexibility Required	hardship anticipated	hardship anticipated	major strain on all regions
Refined Petroleum Product Shortages	modest regional impacts	modest regional impacts	very large increase
Foreign Crude Imports Increases	large gradual increase	depends on refinery flexibility	large sudden decrease
Employment Foregone	large on national basis	proportionally smaller than NOS	large in affected industries
Investment Foregone	large on national basis	proportionally smaller than NOS	possible increase in fuel switching investment
Producer Impacts	sign of troubled industry outlook	shut-in heavy always a problem	supply badly needed
Consumer Impacts	macro impacts lost	macro impacts last	rationing or price increases
Security of Supply	much greater foreign dependence	proportionally greater dependence	significant hardship

difficulties faced by refiners and pipeline operators. These factors are not well articulated in the model. Product quality constraints, detailed unit operation and yield, real life refining economies and oil transportation costs are not addressed in detail by the model.

The implication is that, unless there is skilled supervision of the model operation and careful simulation results interpretation, incorrect policy decisions could be made. These could have adverse effects during a serious supply disruption, if the model results were allowed to form the basis of an allocation program.

5.2 Future Research

Further work regarding the impacts of changing crude oil supplies should focus on three major areas:

- the regional technical flexibility of refiners, with specific emphasis on plant economics;
- the changes in supply patterns likely to occur, including allocation of crude types regionally; and
- the economics of heavy crude oil upgrading, residual fuel oil upgrading, and future refinery rationalization.

Future research would require an extremely detailed and well articulated regional refinery linear programming model. Rigorous attention would have to be paid to refinery-specific circumstances, including the effects of competitive market forces that operate in each refining region.

Such a study would constitute a major effort, and require the ongoing use of the model envisaged to justify its development costs.

APPENDIX A

MODEL INPUT DATA

TABLE A.1

1990 CRUDE OIL SUPPLY SCENARIOS
($10^3 m^3/d$)

		Source Code[a]	Base Case (BAS)	No New Oilsands[b] (NOS)	No Heavy Crude Up-Grader[b] (NUG)	Reduced Foreign Supply[b] (RFS)
007	Arabian Light	(O)	34.779	*58.929	34.254	*12.000
013	B.C. Light	(C)	1.602	1.602	1.602	1.602
014	Boundary Lake	(C)	1.489	1.489	1.489	1.489
015	Bow River	(C)	2.468	2.468	2.468	2.468
018	BCP17	(O)	9.111	*18.771	8.901	* -
022	Chauvin	(C)	0.288	0.288	0.288	0.288
023	Coleville-Smiley	(C)	1.039	1.039	1.039	1.039
024	Condensate	(C)	6.516	6.516	6.516	6.516
027	Ellerslie	(C)	-	-	-	-
028	Cremona	(C)	-	-	-	-
030	Federated Pl.	(C)	3.381	3.381	3.381	3.381
032	Fost./Dollard	(C)	2.006	2.006	2.006	2.006
047	G.C.O.S. A	(C)	9.000	9.000	9.000	9.000
043	Synthetic Crude (SYN)	(C)	78.000	*32.000	*71.000	78.000
045	Gulf Alberta	(O)	-	-	-	-
058	Isthmus	(C)	4.556	*9.386	4.451	1.077
061	Kaybob Condensate	(C)	1.077	1.077	1.077	18.729
074	Lloydminster Blend	(C)	18.729	*18.729	*26.729	3.167
080	Midale	(C)	3.167	3.167*	3.167	2.721
081	Midale/Weyburn-CDC M	(C)	2.721	2.721	2.721	37.007
083	M.S.O.	(C)	37.007	37.007	37.007	32.342
086	MSW	(C)	32.342	32.342	32.342	0.477
092	Norman Wells	(C)	0.477	0.477	0.477	0.082
103	Ontario	(C)	0.082	0.082	0.082	3.412
110	Peace River Crude	(C)	3.412	3.412	3.412	5.714
111	Pembina	(C)	5.714	5.714	5.714	4.559
120	Rainbow Blend	(C)	4.559	4.559	4.559	-
123	Redwater	(O)	-	-	-	* -
141	T. J. Light	(O)	9.111	*18.771	*8.901	-
146	Texaco Common		-	-	-	

[a]Source Code: O = offshore and C = Canada.

[b]Asterisks indicate values significantly different from base case.

TABLE A.2

1990 BASE CASE REFINED PETROLEUM PRODUCT DEMAND SCENARIO[a]
($10^3 m^3/d$)

	Atlantic	Quebec	Ontario	Prairies	B.C.
Petrochemical Feedstock	0.217	7.772	11.863	3.657	0.257
Motor Gasoline	7.980	19.718	31.558	23.451	13.173
Stove Oil	0.517	0.688	0.689	0.764	0.264
Furnance Fuel Oil	4.535	5.856	6.041	0.774	2.315
Heavy Fuel Oil	5.190	5.689	4.579	0.289	1.406
Asphalt	2.166	3.222	4.591	5.952	2.109
Lube	0.499	0.888	2.358	1.346	0.637
Other	0.062	2.105	2.829	1.313	1.406
Diesel	6.350	9.639	14.643	20.299	10.922
Jet A-1	1.132	2.546	3.951	2.730	1.351
Jet B	0.462	0.849	1.388	1.603	1.944
Low V Heavy Fuel Oil	-	-	-	-	-
TOTAL	29.060	58.952	84.490	62.178	35.784

[a]Recent trends in Canadian oil demand have rendered this demand scenario somewhat high. This is discussed further in Section 3.2.

APPENDIX B

MODEL OUTPUT DESCRIPTION

Appendix B

MODEL OUTPUT DESCRIPTION

B.1 Crude Allocation

B.1.1 General Comments

Figure B.1a shows the crude allocation by density range and region for all four cases. The Atlantic, Prairies and B.C. regions experience very little disruption in supply between BAS, NOS and NUG cases (see Table 3.1 for case acronyms), hence the refined product slates in these regions are not disrupted.

It is interesting to note that the amount of crude allocated to Quebec increased for the NOS and NUG scenarios (see Figure B.1a). This is necessary since the quality of crude received decreases but production of important light end products is maintained.

Conversely, the amount of crude allocated to Ontario decreases for both the NOS and NUG cases. This is due to the composition of crude changing such that quantities of heavy fuel and furnace fuel fractions are reduced, while quantities of lighter fractions are maintained.

All regions experience reduced crude supply for the RFS scenario. Even though the Atlantic and Quebec regions are the only consumers of foreign crude, the other three regions experience shortages due to a general eastward reallocation.

With greatly reduced foreign crude being refined during the RFS case, the overall quality of crude supplied is improved. The result of this is that the production levels of heavy and furnace fuel oil are more significantly reduced than those of the more valuable lighter products.

Figure B1a: Crude Distribution by Density

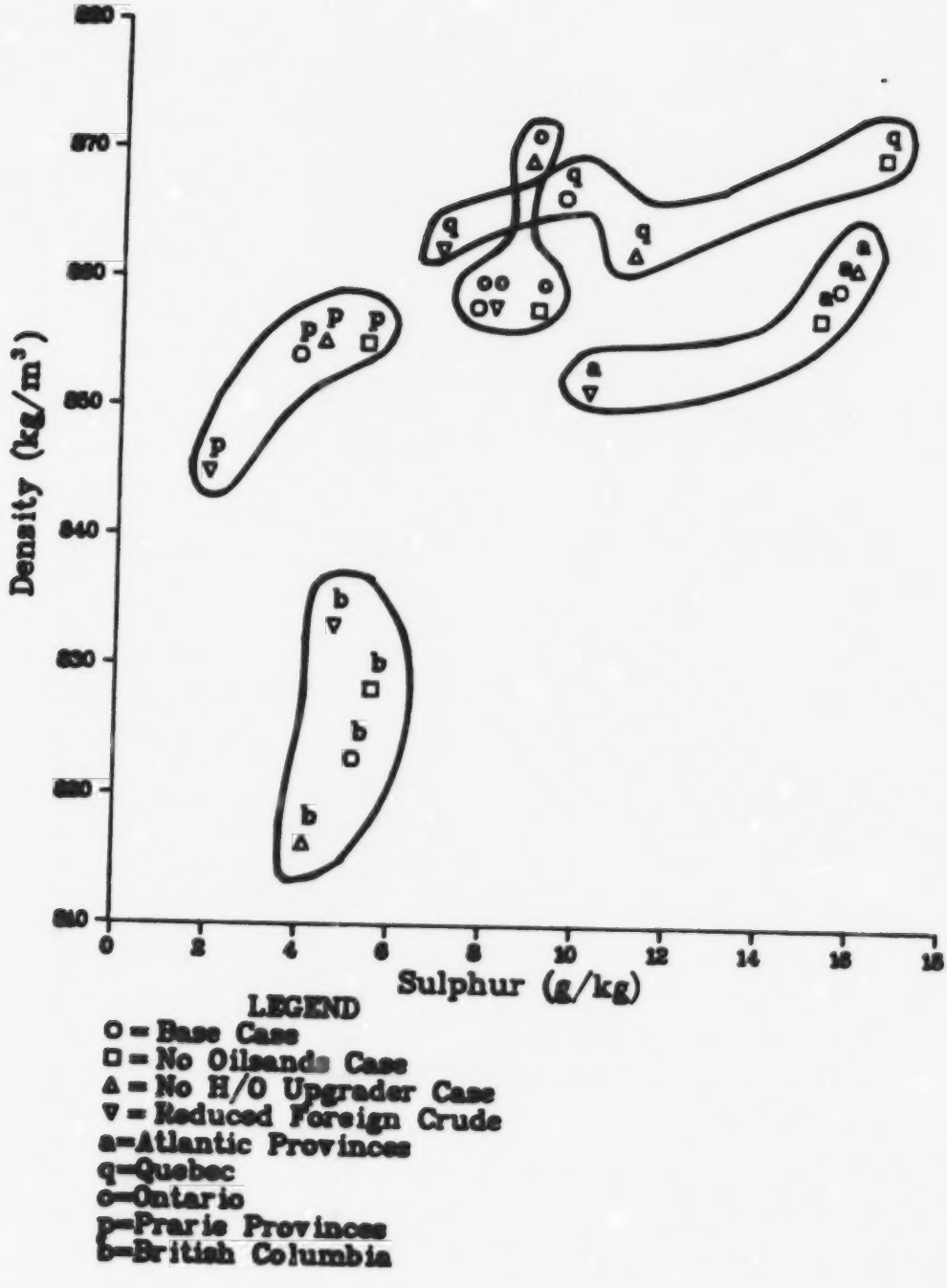

Figure B.ib: Crude Density vs Crude Sulphur Content

The raw data used in constructing Figure B.1a are given in Tables C.1a through C.1e.

B.1.2 Foreign Crude Allocation

Foreign crude is refined only in the Quebec and Atlantic regions. Tables B.1a through B.1d show the breakdown of foreign crude allocation.

The amount of foreign crude allocated to Quebec changes from 24 000 m^3/day for the BAS case to 71 000 m^3/day for the NOS case. This is due to all of Quebec's base case domestic crude supply being reallocated to regions west of Quebec to compensate for shortages created by stagnant oilsands development.

The amount of foreign crude allocated to Quebec under the NUG scenario is about equal to that supplied under base case conditions. This is true for Canada in general. In other words, the shortages created by the NUG scenario are compensated for by domestic reallocation; the foreign crude supply scene is virtually identical for both the base case and NUG case.

For the RFS case, foreign crude available to Canada is reduced to 12 400 m^3/day. This results in generally reduced refinery production, especially that of heavy products. Domestic crude is reallocated eastward to make up for the shortfall experienced in the Atlantic and Quebec regions.

B.1.3 Crude Density versus Crude Sulphur Content

Figure B.1b gives the relationship between composite crude density and composite crude sulphur content for all four scenarios. The general proximity of regional points among different cases demonstrates what appears to be the model's attempt to supply consistent crude quality to each region. Some anomalies are apparent though.

The large variation between cases in sulphur content of crude for Quebec is caused by the large influx of foreign crude for the NOS case and the large drop in foreign crude for the RFS case. The foreign crude allocated is of a high

TABLE B.1a

1990 - BASE CASE - FOREIGN CRUDE SUPPLY
($10^3 m^3$/day)

Crude Type	ATL	QUE	ONT	PRA	BC	Canadian Total
(07) Arabian Light	19.97	15.97	-	-	-	35.94
(18) BCF 17	-	8.00	-	-	-	8.00
(58) Isthmus	4.77	-	-	-	-	4.77
(141) TJ Light	9.40	-	-	-	-	9.40
Regional	34.14	23.97	-	-	-	58.11

TABLE B.1b

1990 - NO NEW OILSANDS - FOREIGN CRUDE SUPPLY
($10^3 m^3$/day)

Crude Type	ATL	QUE	ONT	PRA	BC	Canadian Total
(07) Arabian Light	14.60	44.33	-	-	-	58.93
(18) BCF 17	-	15.60	-	-	-	15.60
(58) Isthmus	9.70	-	-	-	-	9.70
(141) TJ Light	7.85	11.33	-	-	-	19.18
Regional	32.15	71.26	-	-	-	103.41

TABLE B.1c

1990 - NO HEAVY OIL UPGRADER
FOREIGN CRUDE SUPPLY
(10^3m^3/day)

Crude Type	ATL	QUE	ONT	PRA	BC	Canadian Total
(07) Arabian Light	19.40	16.03	-	-	-	35.43
(18) BCF 17	-	7.73	-	-	-	7.73
(58) Isthmus	4.67	-	-	-	-	4.67
(141) TJ Light	9.20	-	-	-	-	9.20
Regional	33.27	23.76	-	-	-	57.03

TABLE B.1d

1990 - REDUCED FOREIGN CRUDE SUPPLY
FOREIGN CRUDE SUPPLY
(10^3m^3/day)

Crude Type	ATL	QUE	ONT	PRA	BC	Canadian Total
(07) Arabian Light	8.67	3.73	-	-	-	12.40
Regional	8.67	3.73	-	-	-	12.40

sulphur content and hence, affects composite sulphur levels significantly.

The density of Ontario crude increases for the NUG case due to less condensate and more synthetic crude being supplied.

The variations in crude density for the B.C. regions are caused by slight changes in the B.C. allocations of condensate (very light), Fost./Dollard crude (very heavy) and synthetic crude (medium density).

B.2 Refinery Production

B.2.1 Motor Gasoline

Production of motor gasoline is fairly stable for all four cases (see Figure B.2a) The Quebec region shows a slight surplus for the NUG case. This is due to an increase in light crude (density<850 kg/m^3) allocation to Quebec. See Figure B.1a.

The B.C. region experiences a deficit for all four cases due to refinery limitations. This deficit is compounded in the RFS case due to a general reallocation eastward of light and medium crude to compensate for reduced foreign supply.

B.2.2 Diesel Fuel

Both the Prairies and B.C. regions experience deficits in diesel production due to refining capacity constraints. See Figure B.2b.

The Atlantic region experiences a deficit in diesel production under the RSF scenario. This is part of the effect of a 24 percent reduction (relative to base case) in crude allocated to the Atlantic region for this scenario.

B.2.3 Heavy Fuel Oil

All five regions experience a surplus of heavy fuel oil for the base case, the NOS case and the NUG case. This

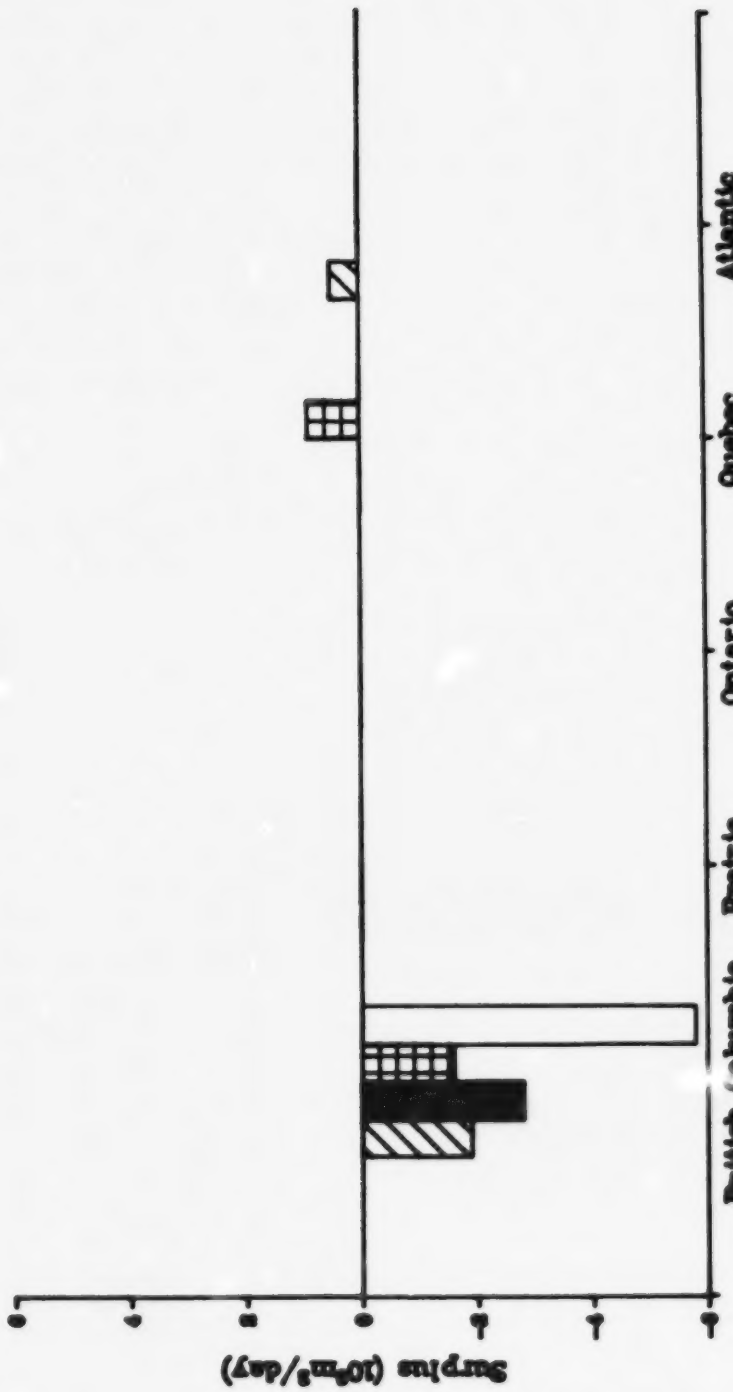

Figure B2a: Gasoline Production Trends

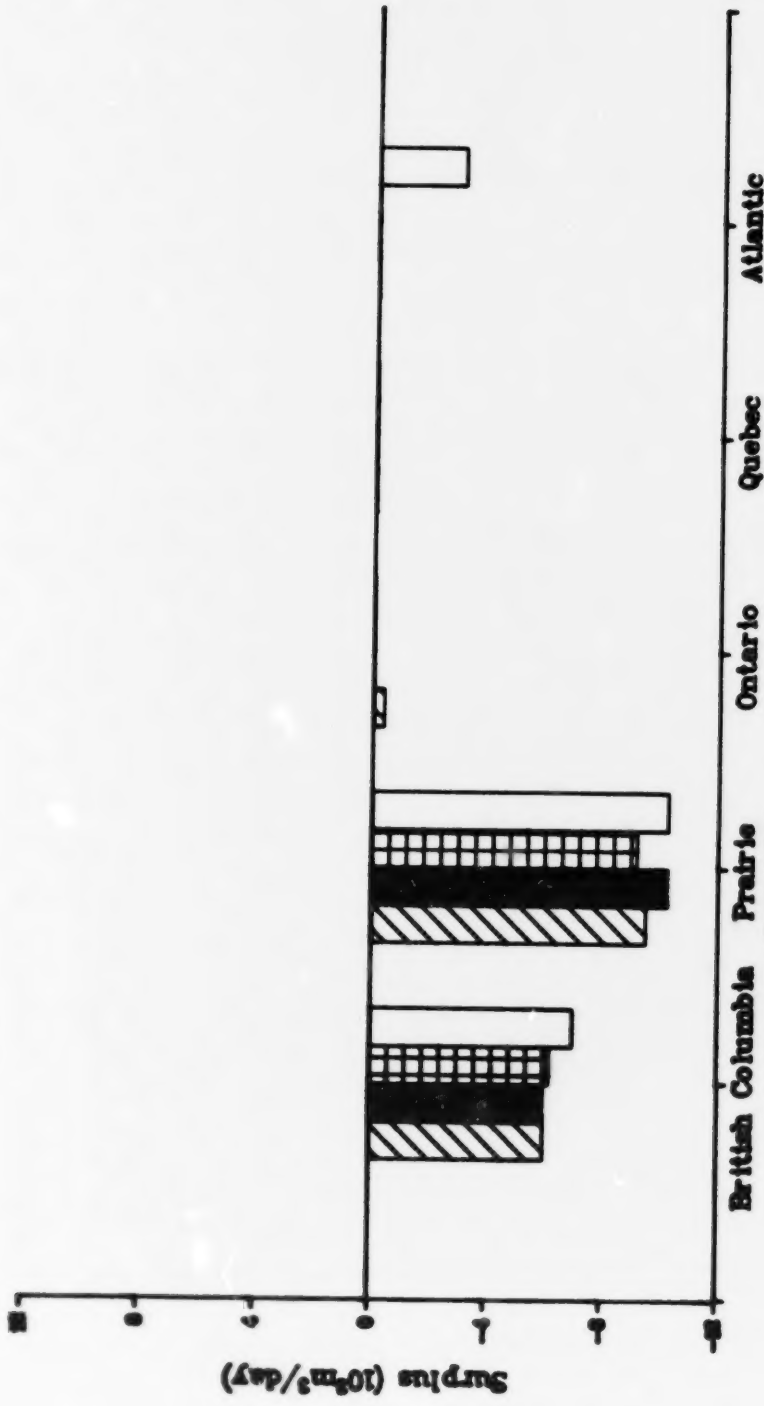

Figure B2b: Diesel Fuel Production Trends

is due to the ever-present heavy fraction in crude supplies combined with low demand for heavy products. See Figure B.2c.

This surplus is not evident during the RFS scenario due to reduced volumes of crude available to all regions (caused by reduced low quality foreign crude).

There is a large increase in the Quebec region surplus for the NOS scenario relative to base case. This is due to an approximately 200 percent increase in foreign crude supplied which is of a generally lower quality than domestic crude. See Tables B.1b and B.2b.

There is a slight increase in Quebec surplus, relative to base case for the NUG case. This is due to a 10 percent increase in heavy crude (density <900 kg/m^3) supplied during the case. See Figure B.1a.

The surplus in Ontario is reduced relative to base case for both the NOS and NUG cases. This is due to a corresponding reduction in crude supplied to Ontario, the composition of which is lower in the heavy fuel oil fraction.

B.2.4 Petrochemical Feedstock

Quebec and Prairie regions exhibit deficits in petrochemical feedstock production. This is due to refinery limitations. See Figure B.2d.

B.2.5 Furnace Fuel Oil

All regions experience a surplus in furnace fuel oil, with Ontario experiencing the greatest excess. This is due to a generally low demand for heavy fractions (see Figure B.2e).

Ontario experiences a decrease relative to base case in this surplus for both the NOS and NUG cases. This is due to the increased quality of crude supplied to Ontario, relative to the base case. See Figure B.1a.

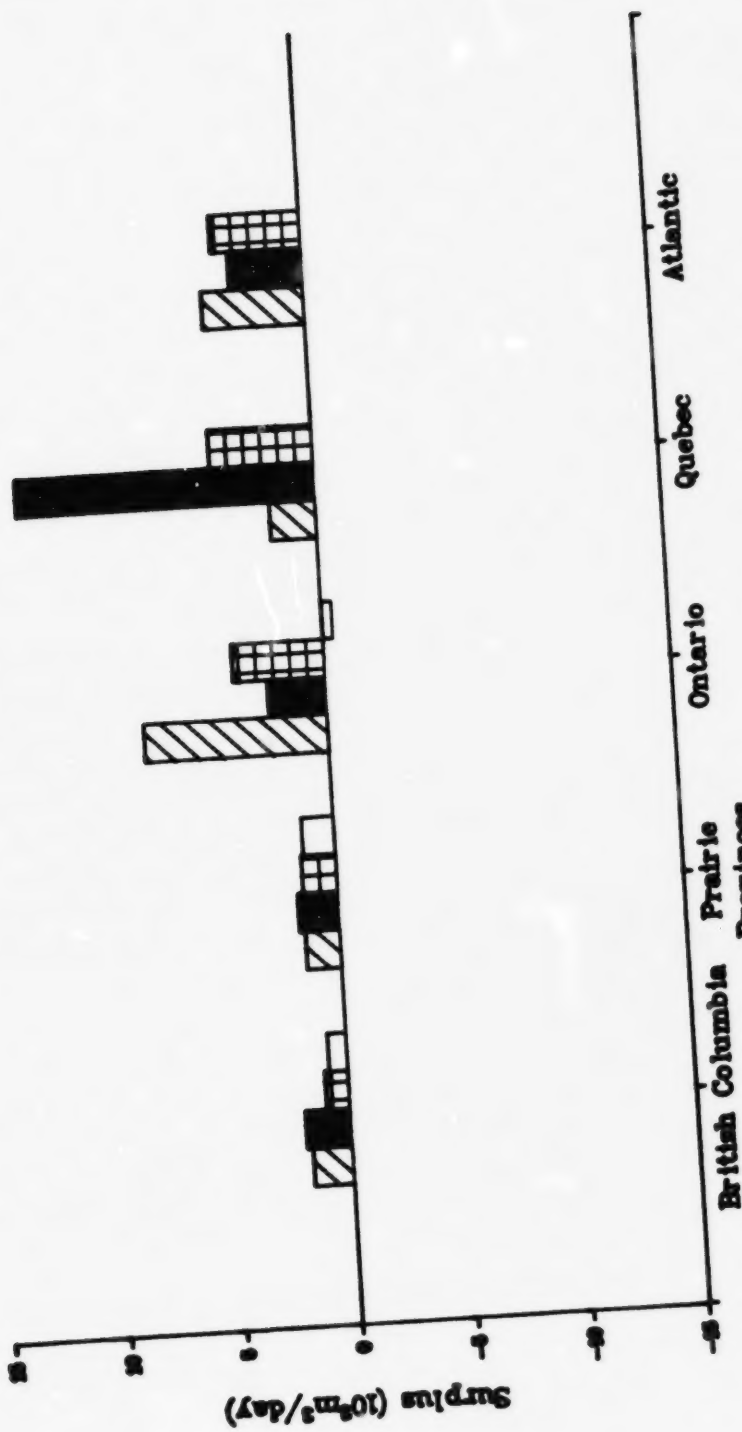

Figure B2c: Heavy Fuel Production Trends

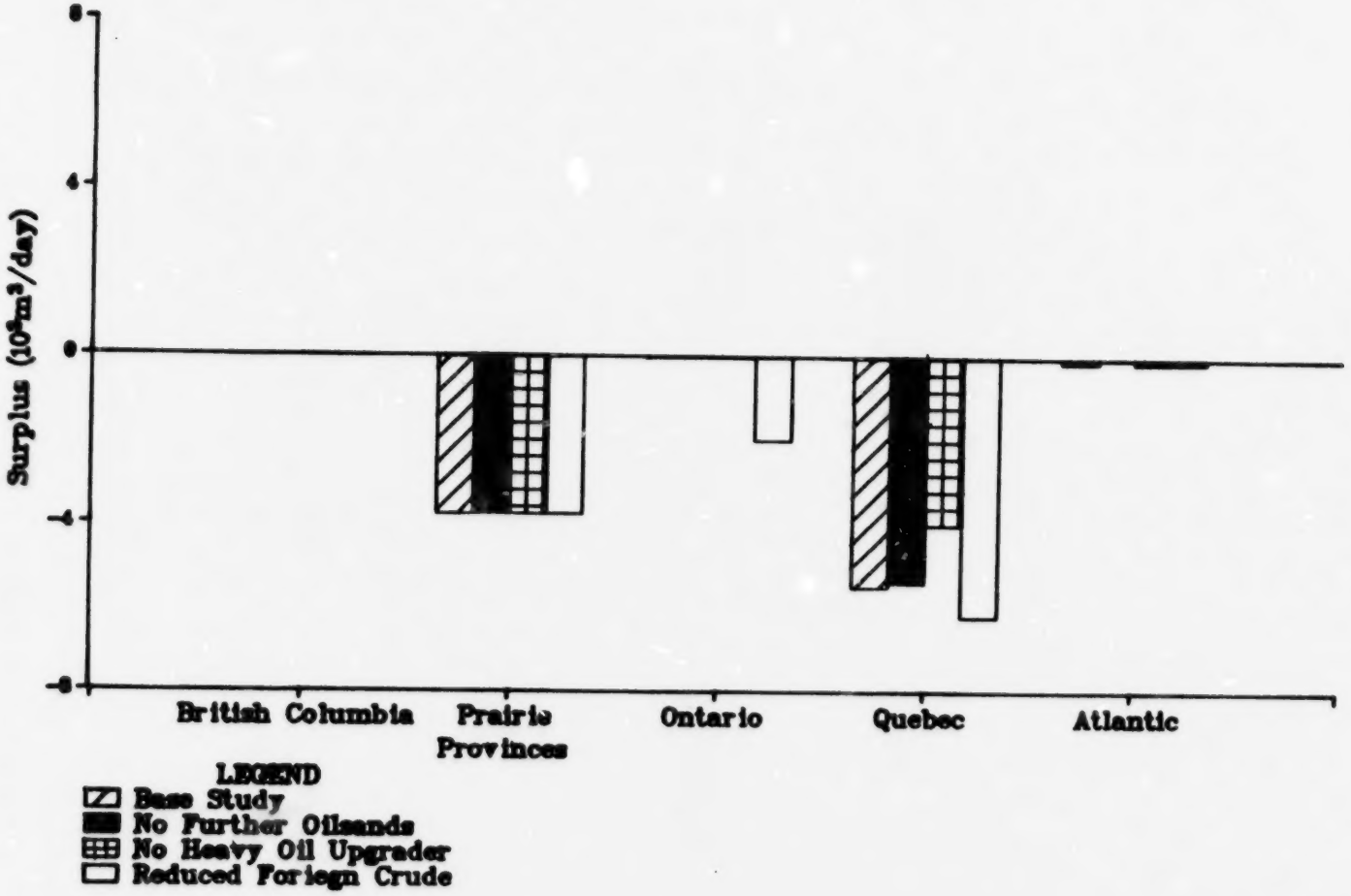

Figure B.2d: Petrochemical Feedstock Production Trends

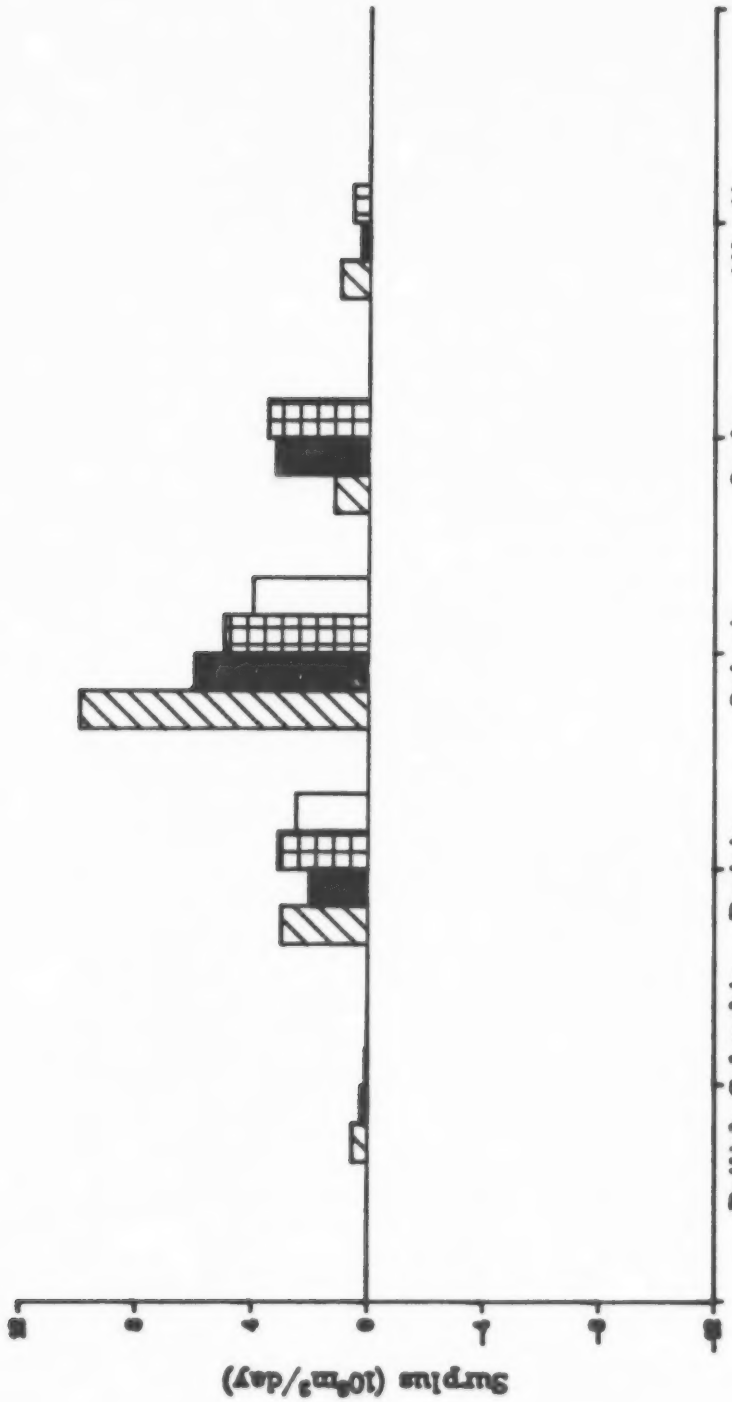

Figure B2e: Furnace Fuel Production Trends

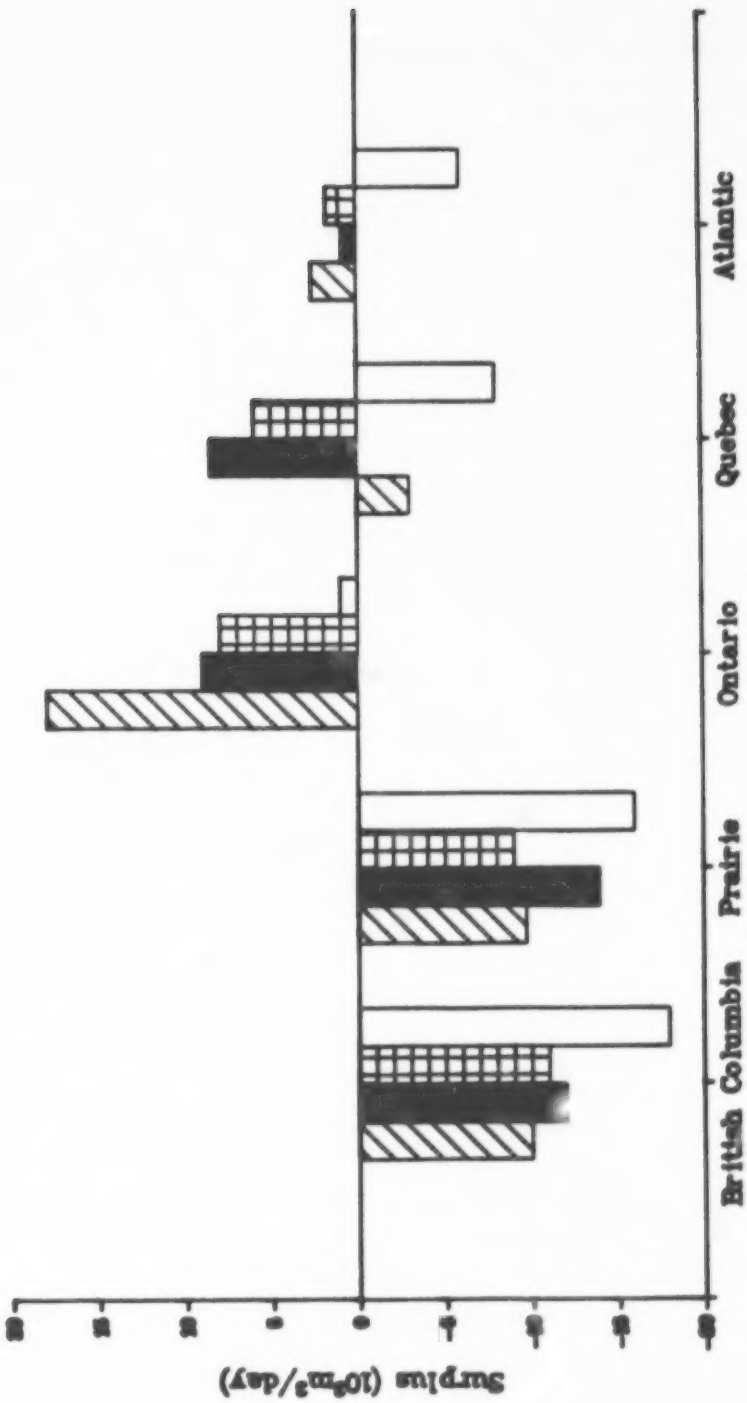

Figure B2f: Total Canada RFC Production Trends

The surplus is less in all regions for the RFS scenario due to significantly less crude available.

B.2.6 Total Canadian Surplus/Deficit

The overall Canadian surplus for all regions and all three scenarios is given by Figure B.2f. The variations in surplus in the Quebec and Ontario regions are caused mainly by fluctuations in heavy fuel and furnace fuel production. These products were discussed in detail in the previous sections.

Figure B.2f shows the significant effect of a foreign crude oil curtailment for Canada. All regions except Ontario experience overall deficits.

The raw data used to construct Figures B.2a through B.2f are given in Tables C.2a through C.2d.

APPENDIX C

MODEL OUTPUT RAW DATA

TABLE C.1a

1990 - ATLANTIC CRUDE SUPPLY ALLOCATION
(10^3m^3/day)

Crude Type	Base Case	No New Oilsands	No H/O Upgrader	Reduced Foreign Crude
Arabian Light	19.97	14.60	19.40	8.67
Bow River	-	-	-	2.60
Isthmus	4.77	9.70	4.67	-
MSO	-	-	-	11.37
Peace River Crude	-	-	-	3.50
T. J. Light	9.40	7.85	9.20	-
TOTAL CRUDE	34.14	32.15	33.27	26.13

TABLE C.1b

1990 - QUEBEC CRUDE SUPPLY ALLOCATION
($10^3 m^3$/day)

Crude Type	Base Case	No New Oilsands	No H/O Upgrader	Reduced Foreign Crude
Arabian Light	15.97	44.33	16.03	3.73
BCF 17	8.00	15.60	7.73	-
Condensate	1.67	-	2.07	-
Syncrude	29.50	-	14.80	26.37
Lloyd Blend	4.23	-	5.00	5.63
Midale	-	-	1.67	0.30
Midale/Weyburn	-	-	2.80	2.80
MSO	-	-	13.63	6.60
MSW	-	-	2.97	7.43
T. J. Light	-	11.33	-	-
TOTAL CRUDE	59.37	71.26	66.70	52.86

TABLE C.1c

1990 - ONTARIO CRUDE SUPPLY ALLOCATION
($10^3 m^3$/day)

Crude Type	Base Case	No New Oilsands	No H/O Upgrader	Reduced Foreign Crude
Bow River	2.60	2.13	2.60	-
Chauvin	0.30	0.30	-	0.30
Coleville-Smiley	1.03	1.03	1.03	1.03
Condensate	1.23	3.73	-	4.43
GCOS	7.63	7.80	7.63	7.63
Syncrude	15.30	5.80	22.73	19.77
Lloyd Blend	10.80	13.97	17.23	12.77
Midale	2.63	1.67	-	3.00
Midale/Weyburn	2.80	2.80	-	-
MSO	34.97	31.30	20.93	20.27
MSW	26.77	26.77	23.80	19.33
Ontario	-	0.10	-	0.10
TOTAL CRUDE	106.06	97.40	95.97	88.63

TABLE C.1d

1990 - PRAIRIE CRUDE SUPPLY ALLOCATION
($10^3 m^3$/day)

Crude Type	Base Case	No New Oilsands	No H/O Upgrader	Reduced Foreign Crude
Bow River	-	0.43	-	-
Condensate	1.67	1.97	1.97	1.87
Federated Pl.	-	-	-	1.30
GCOS	1.67	1.53	1.67	1.67
Syncrude	32.40	23.87	32.40	29.17
Lloyd Blend	4.27	5.37	5.37	-
MSO	1.07	5.70	1.07	0.93
MSW	6.60	6.60	6.60	6.60
Norman Wells	0.53	0.53	0.53	0.53
Pembina	5.90	5.90	5.90	5.90
Rainbow Blend	-	-	0.53	-
TOTAL CRUDE	54.10	51.90	56.03	47.97

TABLE C.1e

1990 - B.C. CRUDE SUPPLY ALLOCATION
($10^3 m^3$/day)

Crude Type	Base Case	No New Oilsands	No H/O Upgrader	Reduced Foreign Crude
BC Light	1.67	1.67	1.67	1.67
Boundary Lake	1.57	1.57	1.57	1.57
Condensate	2.17	1.03	2.70	0.40
Federated Pl.	3.50	3.50	3.50	2.23
Fost./Dollard	1.33	1.33	-	1.33
Syncrude	3.40	3.40	3.40	5.33
Kaybob Condensate	1.13	1.13	1.13	1.13
Midale	0.67	1.67	1.67	-
MSO	2.23	1.23	2.60	-
Peace River Crude	3.50	3.50	3.50	-
Rainbow Blend	4.77	4.77	4.23	4.77
TOTAL CRUDE	25.93	24.80	25.97	18.43

TABLE C.2a

1990 - BASE CASE: PRODUCTION AND DEMAND
($10^3 m^3$/day)

	Atlantic	Quebec	Ontario	Prairies	B.C.	Canada
PRODUCTION						
Petro. Chem. Feed	0.13	2.33	12.27	0.00	0.33	15.10
Motor Gasoline	8.50	20.37	32.60	24.23	11.67	97.37
Diesel	6.57	9.97	14.77	11.43	4.87	47.60
Jet Fuel A	1.17	2.63	4.07	2.83	0.83	11.53
Jet Fuel B	0.33	0.87	1.43	1.67	0.10	4.53
Stove Oil	0.23	1.83	0.93	4.40	0.37	7.77
Furnace Fuel Oil	5.70	6.90	17.17	3.83	2.93	36.53
Heavy Fuel Oil	9.80	7.47	12.60	1.70	2.87	34.47
Asphalt	0.00	3.33	3.93	2.20	0.20	9.67
Lubrication	0.00	0.00	2.60	0.30	0.00	2.90
Total Production	32.60	55.73	102.40	52.60	24.17	267.50
DEMAND						
Petro. Chem. Feed	0.23	8.03	12.27	3.77	0.27	24.57
Motor Gasoline	8.23	20.37	32.60	24.23	13.60	99.07
Diesel	6.57	9.97	15.13	20.97	11.30	63.90
Jet Fuel A	1.17	2.63	4.07	2.83	1.40	12.10
Jet Fuel B	0.47	0.87	1.43	1.67	2.00	6.47
Stove Oil	0.53	0.70	0.70	0.80	0.27	3.00
Furnace Fuel Oil	4.70	6.03	6.23	0.80	2.40	20.17
Heavy Fuel Oil	5.37	5.87	4.73	0.30	1.47	17.73
Asphalt	2.23	3.33	4.73	6.13	2.17	18.63
Lubrication	0.50	0.90	2.43	1.40	0.67	5.90
Total Demand	30.00	58.73	84.37	62.90	35.53	271.57
Surplus	2.60	-3.03	18.03	-10.30	-11.33	-4.03
Refining Capacity	60.97	106.43	128.13	60.67	29.67	385.83
Throughput	34.13	59.53	106.03	54.07	25.93	279.70
Percent Capacity	55.99	55.93	82.76	89.16	87.46	72.50

TABLE C.2b

1990 - NO FURTHER OILSANDS DEVELOPMENT: PRODUCTION AND DEMAND
($10^3 m^3$/day)

	Atlantic	Quebec	Ontario	Prairies	B.C.	Canada
PRODUCTION						
Petro. Chem. Feed	0.30	2.37	12.27	0.00	0.30	15.20
Motor Gasoline	8.23	20.37	32.60	24.23	10.83	96.30
Diesel	6.57	9.97	15.13	10.70	5.00	47.33
Jet Fuel A	1.17	2.63	4.07	1.83	0.97	10.67
Jet Fuel B	0.47	0.87	1.43	1.67	0.10	4.53
Stove Oil	0.53	0.70	0.70	2.93	0.37	5.27
Furnace Fuel Oil	4.97	8.40	12.80	3.27	2.60	32.00
Heavy Fuel Oil	8.53	19.23	7.80	2.17	2.93	40.73
Asphalt	0.00	3.33	4.73	2.53	0.23	10.83
Lubrication	0.00	0.00	2.50	0.40	0.00	2.90
Total Production	30.80	67.87	94.07	49.77	23.30	265.80
DEMAND						
Petro. Chem. Feed	0.23	8.03	12.27	3.77	0.27	24.57
Motor Gasoline	8.23	20.37	32.60	24.23	13.60	99.07
Diesel	6.57	9.97	15.13	20.97	11.30	63.90
Jet Fuel A	1.17	2.63	4.07	2.83	1.40	12.10
Jet Fuel B	0.47	0.87	1.43	1.67	2.00	6.47
Stove Oil	0.53	0.70	0.70	0.80	0.27	3.00
Furnace Fuel Oil	4.70	6.03	6.23	0.80	2.40	20.17
Heavy Fuel Oil	5.37	5.87	4.73	0.30	1.47	17.73
Asphalt	2.23	3.33	4.73	6.13	2.17	18.63
Lubrication	0.50	0.90	2.43	1.40	0.67	5.90
Total Demand	30.00	58.73	84.37	62.90	35.53	271.57
Surplus	0.80	9.13	9.70	-13.13	-12.23	-5.77
Refining Capacity	60.97	106.43	128.13	60.67	29.67	385.83
Throughput	32.17	71.30	97.33	51.87	24.80	277.47
Percent Capacity	52.74	67.00	75.96	85.53	83.62	71.91

TABLE C.2c

1990 - NO HEAVY OIL UPGRADER: PRODUCTION AND DEMAND
($10^3 m^3$/day)

	Atlantic	Quebec	Ontario	Prairies	B.C.	Canada
PRODUCTION						
Petro. Chem. Feed	0.13	3.37	12.27	0.00	0.37	16.13
Motor Gasoline	8.23	21.10	32.60	24.23	12.00	98.20
Diesel	6.57	9.97	15.13	11.73	4.70	48.10
Jet Fuel A	1.17	2.63	4.07	2.83	0.73	11.43
Jet Fuel B	0.47	0.83	1.43	1.67	0.10	4.53
Stove Oil	0.53	3.70	0.70	4.57	0.37	9.90
Furnace Fuel Oil	5.27	8.47	11.53	4.07	3.07	32.43
Heavy Fuel Oil	9.30	9.80	8.13	1.73	2.50	31.50
Asphalt	0.00	3.33	4.37	2.67	0.20	10.53
Lubrication	0.00	0.00	2.43	0.30	0.00	2.73
Total Production	31.73	63.27	92.70	53.73	24.07	265.50
DEMAND						
Petro. Chem. Feed	0.23	8.03	12.27	3.77	0.27	24.57
Motor Gasoline	8.23	20.37	32.60	24.23	13.60	99.07
Diesel	6.57	9.97	15.13	20.97	11.30	63.90
Jet Fuel A	1.17	2.63	4.07	2.83	1.40	12.10
Jet Fuel B	0.47	0.87	1.43	1.67	2.00	6.47
Stove Oil	0.53	0.70	0.71	0.80	0.27	3.00
Furnace Fuel Oil	4.70	6.03	6.23	0.80	2.40	20.17
Heavy Fuel Oil	5.37	5.87	4.73	0.30	1.47	17.73
Asphalt	2.23	3.33	4.73	6.13	2.17	18.63
Lubrication	0.50	0.90	2.43	1.40	0.67	5.90
Total Demand	30.00	58.73	84.37	62.90	35.53	271.57
Surplus	1.70	4.53	8.30	-9.17	-11.47	-6.07
Refining Capacity	60.97	106.43	128.13	60.67	29.67	385.83
Throughput	32.27	66.67	95.97	56.00	25.93	277.83
Percent Capacity	54.55	62.63	74.90	92.33	87.46	72.01

TABLE C.2d

1990 - REDUCED FOREIGN CRUDE CASE: PRODUCTION AND DEMAND
($10^3 m^3$/day)

	Atlantic	Quebec	Ontario	Prairies	B.C.	Canada
PRODUCTION						
Petro. Chem. Feed	0.13	1.40	10.50	0.00	0.20	12.27
Motor Gasoline	8.23	20.37	32.60	24.23	7.93	93.40
Diesel	3.47	9.97	15.13	10.70	3.87	43.13
Jet Fuel A	1.17	2.63	4.07	2.83	0.43	11.13
Jet Fuel B	0.47	0.87	1.43	1.67	0.10	4.53
Stove Oil	0.53	0.70	0.70	2.20	0.37	4.53
Furnace Fuel Oil	4.70	6.03	10.07	3.33	2.40	26.57
Heavy Fuel Oil	5.50	5.87	4.30	1.53	2.03	19.27
Asphalt	0.83	2.47	4.60	0.70	0.23	8.83
Lubrication	0.00	0.00	1.90	0.23	0.00	2.13
Total Production	25.07	50.33	85.37	47.43	17.57	225.77
DEMAND						
Petro. Chem. Feed	0.23	8.03	12.27	3.77	0.27	24.57
Motor Gasoline	8.23	20.37	32.60	24.23	13.60	99.07
Diesel	6.57	9.97	15.13	20.97	11.30	63.90
Jet Fuel A	1.17	2.63	4.07	2.83	1.40	12.10
Jet Fuel B	0.47	0.87	1.43	1.67	2.00	6.47
Stove Oil	0.53	0.70	0.70	0.80	0.27	3.00
Furnace Fuel Oil	4.70	6.03	6.23	0.80	2.40	20.17
Heavy Fuel Oil	5.37	5.87	4.73	0.30	1.47	17.73
Asphalt	2.23	3.33	4.73	6.13	2.17	18.00
Lubrication	0.50	0.90	2.43	1.40	0.67	5.90
Total Demand	30.00	58.73	84.37	62.90	35.53	270.93
Surplus	-4.93	-8.40	0.97	-15.47	-17.97	-45.17
Refining Capacity	60.97	106.43	128.13	60.67	29.67	385.83
Throughput	26.13	52.87	88.63	47.93	18.40	233.93
Percent Capacity	42.89	49.66	69.17	79.00	62.02	60.63

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